NOVEMBER 2005

# Petroleum review


## ASIA-PACIFIC

- Putting the pieces of the energy jigsaw together

## LUBRICANTS

- Emissions legislation driving EU oil quality

## RUSSIA

- Gazprom-Sibneft: a multi-dimensional deal

*Covering the international oil and gas industry from field to forecourt – exploration, production, refining and marketing*

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# Petroleum review

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**ABBREVIATIONS**

The following are used throughout *Petroleum Review*:

| | |
|---|---|
| mn = million ($10^6$) | kW = kilowatts ($10^3$) |
| bn = billion ($10^9$) | MW = megawatts ($10^6$) |
| tn = trillion ($10^{12}$) | GW = gigawatts ($10^9$) |
| cf = cubic feet | kWh = kilowatt hour |
| cm = cubic metres | km = kilometre |
| boe = barrels of oil equivalent | sq km = square kilometres |
| b/d = barrels/day | |
| t/y = tonnes/year | t/d = tonnes/day |

No single letter abbreviations are used.
Abbreviations go together eg. 100mn cf/y = 100 million cubic feet per year.

**Front cover picture: Putting the pieces of the energy jigsaw together. *Petroleum Review's* Asia-Pacific overview starts on p12**



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# FROM THE EDITOR

## A stunning achievement, but have we reached the yield points?

Over the last month, the oil industry has risen to the challenge of the massive disruption to its Gulf of Mexico oil and gas production, and to its Gulf Coast refining operations. At the time of writing, 67% of oil production (around 1mn b/d) was still shut in, while a similar proportion of gas production was still offline. Eight refineries are still not operational, and there is a dawning realisation that the disruption will last well into 2006. So far, however, all is holding together, with the supply system proving to be more resilient and more flexible than many imagined. However, we are now moving into the winter quarters and it is far from clear how the extra oil and gas demand will be met.

Having briefly glimpsed \$70/b in late August, the current \$60/b oil price appears almost reasonable. In fact, it merely takes us back to the levels of early August and is a staggering 50% above the levels of last December. However, since early August there have been three important developments. Firstly, the choke point in the supply system has moved from being the supply of crude to being the ability to refine it. In particular, the ability to refine high sulphur crude. Secondly, the IEA/US decision to release stocks of both crude and products in the wake of the Katrina and Rita hurricanes, and their aftermath. And thirdly, mounting evidence that demand is starting to wilt in the face of high prices. The alternative, but complementary, explanation is that demand is slowing in line with a normal cyclical economic slowdown. Whatever the exact causation, the result is that, for the first time in over a year, there is rather less pressure on the crude supply system.

So, is \$60–\$70/b some sort of demand yield point? Traders appear to have been wrongfooted by the swift move from a crude supply constraint to a refinery capacity restraint and then a flood of stock release crude and product. The IEA has now revised this year's oil demand growth down to 1.26mn b/d. (As late as June 2005 it was predicting 2005 growth at 1.8mn b/d. It is now predicting 1.7mn b/d for 2006.)

There are, however, a number of reasons to be cautious and to wonder if the current, more benign, situation can last. Barring an almost catastrophic collapse in economic activity, demand for oil products will increase as we move into the winter quarters. The IEA's latest assesssment is that 3Q2005 demand of 82.4mn b/d will rise to 85.5mn b/d in 4Q2005 and ease only fractionally to 85.4mn b/d in 1Q2006. With considerable optimism, the IEA claims that the 3.1mn b/d uplift in demand between the third and fourth quarters can be met. This, in turn, requires the speedy return to operation of the US Gulf refineries, the reliable operation of all the world's major refineries at high levels of throughput and hydroskimming margins to remain positive in order to encourage throughput in the world's less sophisticated refinery units. The IEA also suggests that all refinery maintenance would have to be postponed if requirements are to be met.

At best, this scenario appears highly optimistic. A more realistic expectation is that there will have to be further stock releases this winter. This raises two concerns. Will European governments continue to be relaxed about releasing product stocks from Europe, which has large stocks of oil products, for almost certain use in the US? In contrast to Europe, the US holds all its strategic stocks as crude, apart from a fairly minor 2mn barrels of heating oil stocks in the north-eastern states. The second question is: 'Just how much stock will countries agree to release this year, given that it may not be that easy to replace them?' Particularly if the IEA is right that demand growth will recover to 1.7mn b/d in 2006.

In this issue of *Petroleum Review*, our major feature is on the Asia-Pacific region, which has three key characteristics. It has been the world's fastest developing region in terms of economic growth, oil demand growth and gas demand growth. Regional oil production is broadly flat and may soon move into decline, but meeting regional oil demand involves rising crude imports, overwhelmingly from the Middle East. Regional gas production and consumption are currently broadly balanced, but a rapid demand growth will make the region a net gas importer fairly quickly. As a major importing region it is increasingly in competition with Europe and the US for available supplies.

The other key characteristic of the region has been high levels of government subsidies on many oil products. In the face of rapidly rising oil prices most, although not all, Asia-Pacific governments have reduced or eliminated these subsidies as their budgets could not support them. This, in turn, is seen as the primary cause of the recent slowdown in regional demand. The question now is whether this is a temporary setback as populations adjust to higher prices before growth recommences? Or is it a yield point in which activity is restrained by the higher prices in a more sustained way?

The more facetious commentators have already suggested that the best energy policy at the moment is to pray for a mild winter. With senior figures in the US Republican administration calling on Americans to switch off lights, share cars, and take the train rather than the plane, we may be at the point where even the oil industry's legendary reliability in delivering the product will be put to the test.

*Chris Skrebowski*

The opinions expressed here are entirely those of the Editor and do not necessarily reflect the view of the EI.

# E-DATA

The energy sector is becoming more accountable when it comes to responding to matters that affect social and environmental issues. Five out of the top ten companies listed in The Accountability Rating® 2005 – *Fortune* magazine's annual review of how the world's top companies account for their impacts on society and the environment – are energy producers, with BP and Shell taking first and second places in the table respectively. Other energy producers in the top ten are Tokyo Electric Power (seventh place), Electricité de France (eighth place) and Chevron (tenth place). Visit **www.accountabilityrating.com** for the summary report of results, as well as **www.fortune.com**

A European research project called 'Scenarios for the Transport system and Energy supply and their Potential effectS' (STEPs) was created under the 'sustainable surface transport' priority for the European Union's sixth research framework programme. STEPs has two main objectives – to develop, compare and assess possible scenarios for the transport system and energy supply of the future; and to support the specific future needs of the transport energy sector taking into account the autonomy and security of energy supply, the effects on the environment, economic, technical and industrial viability and interactions between transport and land use. For more information, visit **www.steps-eu.com**

OILspace's 'OILwatch' web-based portal for real-time, aggregated energy prices, news and analysis, which can be found at **www.oilspace.com** is to be rolled out to BP employees throughout the Asia-Pacific region. OILwatch delivers real-time Nymex, IPE futures and Forex ticks, as well as news from sources including Platts, Dow Jones, Petroleum Argus and C1 Energy Prices.

## UK

*Three of the North Sea's independent oil and gas exploration and production companies – Canadian subsidiary Oilexco North Sea, Texas-headquartered Newfield Exploration and UK company Dana Petroleum – have joined the UK Offshore Operators Association (UKOOA) as members, bringing the total number of companies represented by the industry body to 34.*

## EUROPE

*Statoil's Visund platform in the North Sea began exporting gas on 7 October following conversion of the installation to deliver up 5bn cm/y. Some 2bn cm/y of gas will be exported from the field up to 2011. Deliveries will then be increased to 5bn cm/y as less gas will be needed for injection.*

*Statoil (operator) reports that development of the Snøhvit field is expected to cost NKr7bn more than originally forecast, with the final figure now expected to be NKr58.3bn. First gas is expected on 1 June 2007 – eight months later than initially stated.*

## NORTH AMERICA

*Reporting its 3Q2005 figures, BP stated that it expects Hurricanes Katrina and Rita to cost it over $700mn in repair bills and lost profits, putting its 2005 production goal of 4.1–4.2mn boe/d out of reach. Third quarter oil and gas production is now expected to average about 3.8mn boe/d, compared with 4.1mn boe/d in 2Q2005 and 3.9mn boe/d in 3Q2004. Rita and Katrina cost*





# Phase 1 of Sakhalin 1 onstream

**ExxonMobil has commenced production from the multiphase Sakhalin-1 project offshore Eastern Russia. The initial phase of the project will produce 50,000 b/d by year-end 2005 and 250,000 b/d by year-end 2006 from the Chayvo field. Associated domestic gas sales will start at about 1.7mn cm/d and ultimately are expected to increase to about 7.1mn cm/d by the end of the decade.**

**The Sakhalin-1 project, representing one of the largest single foreign direct investments in Russia, involves the construction of both offshore and onshore facilities as part of its initial development phase. These include what is claimed to be the world's largest land-based drilling rig using extended-reach drilling to reach reserves 10 km from shore, an offshore platform that provides drilling capacity for up to 20 wells, an onshore oil and gas processing facility and an associated 225-km crude oil pipeline, and a marine export terminal providing year-round storage and tanker loading facilities on the Russian mainland at DeKastri.**

**Initial natural gas production will be sold to two domestic customers – Khabarovskenergo and Khabarovskkraigas – in the Khabarovsk Krai in the Russian Far East. The buyers will transport the gas to the Khabarovsk Krai through the pipeline systems of Rosneft-Sakhalinmorneftegas and Daltransgas. The potential exists for export of additional gas volumes by pipeline to buyers in Asia.**

**Initial oil production will be sold into the Russian domestic market. Upon completion of the DeKastri oil terminal and pipeline, oil will be sold to international markets by mid-2006.**

**Exxon Neftegas (ExxonMobil interest 30%) is operator for the project, which includes the Japanese company Sakhalin Oil and Gas Development (30%); affiliates of Rosneft, the Russian state-owned oil company, RN-Astra (8.5%), Sakhalinmorneftegas-Shelf (11.5%); and the Indian state-owned oil company ONGC Videsh (20%).**

# *Developing Blind Faith in the GoM*

Chevron has announced that it is proceeding with the development of the Blind Faith field in Mississippi Canyon blocks 695 and 696 in the deepwater Gulf of Mexico. The field will be developed using a semi-submersible production facility, with first production expected during 1H2008. Chevron is the operator and holds a 62.5% working interest. The field has estimated total reserves exceeding 100mn boe.

Total capital costs for the project will be approximately $900mn. Chevron's partner in the Blind Faith project is Kerr McGee, which holds a 37.5% stake.

Initial production is expected to be approximately 30,000 b/d of oil and 30mn cf/d of gas. The semi-submersible facility will have a production capacity of approximately 45,000 b/d and 45mn cf/d. The topsides can be upgraded to a capacity of 60,000 b/d and 150mn cf/d to accommodate production from satellite discoveries or third-party tie-backs, states Chevron.

# Anadarko locks in drilling contracts

Anadarko Petroleum has unveiled a plan to secure the necessary drilling rigs to execute its deepwater strategy over the next six years. Together with two other producers, the company has signed a 4-year rig-share agreement under which ENSCO International will build a new semi-submersible drilling rig with a target delivery date of mid-2008. Anadarko has committed to 50% of the rig time at a cost of almost $200mn over the contract term. Anadarko has also executed a 3-year drilling contract with Dolphin Drilling to secure the *Belford Dolphin* drillship at a cost of $459mn. It is anticipated the vessel will be released to Anadarko in mid-2007. In addition, multi-year contracts worth approximately $1.19bn are being finalised to extend the company's existing contracts and secure incremental rigs. Anadarko currently has two deepwater rigs under contract.

Anadarko's current deepwater Gulf of Mexico development projects include the K2, K2 North and Genghis Khan fields in the Green Canyon area and seven natural gas fields in the Eastern Gulf. Anadarko also has working interests in several non-operated exploration wells currently in progress, including the announced Knotty Head commercial discovery, which will need delineation and development. The company has identified multiple additional prospects throughout the deepwater Gulf and has prospects offshore West Africa, Georgia and Gabon. The company says its expanded rig position could provide leverage into additional opportunities if further tightening of the deepwater rig market materialises.

*BP 145,000 boe/d in the quarter, more than expected and raising fears about the impact of the storms on rivals such as Shell.*

***Mitsubishi Corporation has announced** first oil from a newly developed field in the Mustang Island block 726.*

***Forest Oil and Mariner Energy are** reported to have agreed to a deal under which Forest will spin-off its offshore Gulf of Mexico operation to its shareholders and immediately thereafter merge that operation with a wholly-owned subsidiary of Mariner in a stock-for-stock transaction.*

***Petrobras of Brazil (80%) is reported to** have discovered gas at its Gulf of Mexico Garden Banks 244 block and hopes to start production in 2007.*

### ASIA-PACIFIC

***Santos (40%) has confirmed the dis**covery of a new gas field offshore Australia's Northern Territory with the drilling of the Caldita 1 exploration well, which flowed at a rate of 33mn cf/d.*

***India's ONGC Videsh (20%) and GAIL** (10%) are reported to have signed an agreement with Daewoo of South Korea for a 30% stake in the A-3 gas exploration block in Myanmar.*

***Shell (35%, operator), Petronas** Carigali (30%) and ConocoPhillips (35%) have made another oil and gas discovery in deepwater block G offshore north-west Sabah, Malaysia, with their recent Ubah-2 exploration well.*

### LATIN AMERICA

***Gazprom is to participate in the Phase** A development of the Rafael Urdaneta gas field in Venezuela, having secured licences for the Urumaco I and Urumaco II blocks. US company Chevron has the licence for the Cardon III block development, also part of the Rafael Urdaneta project.*

***Taghmen Energy has been awarded** licence 7-2005 (Tortugas/Atzam) by the Guatemala government. Possible reserves on the licence are estimated to be in the region of 5mn to 16mn barrels of oil.*

***Venezuelan Energy Minister Rafael** Ramirez is reported to have stated that the government may take over fields operated by private companies if they don't convert operating contracts to*

# Helping to discover new oil reserves

**A new method for dating mineral cements containing minute fluid inclusions may ultimately aid the discovery of new oil reservoirs, claim scientists at the University of Aberdeen. Directly establishing the timing of oil migration through a sedimentary basin could help the discovery process, but only indirect dating of oil migration has been possible so far.**

**Led by Professor John Parnell in the School of Geosciences at the University of Aberdeen, and Dr Simon Kelley in the Department of Earth Sciences at the Open University, the scientists are using new analytical techniques to determine when oil accumulated in sandstone rocks deep under the sea between the Shetland Isles and the Faroes.**

**Not all rocks contain oil and over the years billions of pounds have been spent drilling into rocks, which very often prove to be barren. Many things need to be right to trap an economic accumulation of oil in porous sandstone rocks and one of the critical factors is the timing of oil movement.**

**Professor Parnell explains: 'If the potential trap formed before oil flowed into it, there are no problems. However, if it formed after oil was moving, then this is too late and the oil is likely to have leaked to the surface and been lost many millions of years ago. Therefore, in oil exploration it is extremely important to be able to predict when oil was flowing in a particular region – this is the basis of our research, in collaboration with our colleagues at The Open University.'**

**To date, geologists have had to try to predict the oil flow using indirect evidence or theoretical modelling along with quite a bit of 'guesswork'. Now, a novel approach has been proved which can estimate when oil entered a subsurface reservoir. The integrated technique determines the temperature, composition and timing of past-fluid flow. The technique uses a mineral – potassium feldspar – which occurs as a natural cement in many oil reservoirs, filling pore spaces and coating sand grains.**

**The presence of oil during mineral precipitation is recorded in tiny bubbles of oil trapped inside the mineral cement. The age of the feldspar cement can be determined by measuring the amount of argon produced by radioactive decay of potassium. Dating the mineral also dates the occurrence of oil in the reservoir.**

# *Libya's latest licensing round*

On 5 October 2005, Libya held another auction of exploration and production licences for 44 onshore and offshore blocks, writes *Judith Gurney*. These were located in the same areas as those in its January auction – off the coast of Tripoli, in the offshore north-east Cyrenaica basin, and onshore in the central Sirte, west Ghadames, south-east Kufra, and south-west Murzuq basins. However, the blocks offered were considerably smaller than those in the previous auction.

There were successful bids by 17 companies for 40 blocks. But whereas the bidding in January was dominated by US companies, notably Occidental, a wide assortment of European and Asian companies acquired licences in this auction. Awards were made on the basis of the share of future production assigned to NOC, the Libyan state-owned integrated oil company, and the amount of signature bonus offered. Reports differ on the number of companies which participated.

Japanese companies, including Nippon, Mitsubshi, Japex and Teikoku, were awarded nine blocks, three onshore in the Murzug and Ghadames basins and six off the coast of Tripoli and in the Cyrenaica basin. Norway's Statoil and Norsk Hydro were also awarded nine blocks, four offshore in the Cyrenaica basin and five onshore in the Murzuq and Kufra basins. Italy's Eni was awarded eight onshore blocks in the Murzuq and Kufra basins.

British Gas acquired interests in six onshore blocks, two in the Sirte basin and four, in a joint venture with Statoil, in the unexplored Kufra basin. ExxonMobil, the only US company to be successful in this auction, was awarded four offshore blocks in the Cyrenaica basin.

India's ONGC and Oil India, Indonesia's Pertamina, Turkey's Turkish Petroleum Company, and France's Total (in a joint venture with Inpex) were all awarded two blocks. Russia's Techneft acquired one onshore block and China's CNCP one offshore block.

Although not successful in this auction, US companies are continuing to increase their activities in Libya. In late September, Occidental shipped a consignment of Libyan crude to the US, its first lifting of Libyan oil since 1986 when US sanctions prevented it from working its Sirte basin holdings.

*joint ventures with state-run PdVSA by a 31 December 2005 deadline. It is understood that PdVSA may hold up to 80% in the new joint ventures. PdVSA currently has 32 contracts with 22 companies that operate and manage oil fields for it, including Chevron, Repsol YPF and Petroleo Brasileiro.*

### AFRICA

***Total, Repsol, OMV and Saga have** made a new oil discovery in Libya's block NC 186, in the Murzuq basin. The well flowed at a rate up to 2,060 b/d of 40° API oil.*

***Hydro has signed a production sharing** agreement (PSA) with Sonangol for block 4 offshore Angola. Hydro and Sonangol have been exploring the block since early 2003 and a discovery was made in September 2004 under a prospecting licence. The discovery is being evaluated for a stand-alone development. Production is planned to start by the end of 2007. Recoverable reserves are put at 50mn barrels of oil.*

***Eni reports that the ROM 6 exploration** well in Algeria's Berkine basin has tested at more than 5,000 b/d of oil.*

***Petroceltic International has** announced the sale of an option, which, if exercised by March 2008, will result in the farming out of 38% interest in the Ksar Hadada production sharing contract (PSC) onshore south-east Tunisia to Independent Resources. There are two significant prospects – Sidi Toui and Oryx – in the permit.*

***London-based oil and gas exploration** and production company Soco International will be loaned up to \$45mn by the World Bank's International Finance Corporation (IFC) to help finance its investments in emerging markets, particularly Vietnam and Yemen. Soco wants to help stem Yemen's declining oil production and help Vietnam secure more market-based foreign direct investment, reports* Keith Nuthall.

***International well construction perfor**mance company The Peak Group has secured its first contract offshore Mauritania, having won a contract to drill an exploration well for Dana Petroleum. The deepwater well will be drilled on the Faucon prospect in block 1 offshore southern Mauritania. Faucon and its sister prospect, Petrel, each have the potential to contain more than 1bn barrels of oil in place, reports Peak.*

# Promoting Norwegian E&P

The Norwegian Ministry of Petroleum and Energy is proposing new measures concerning the use of facilities by others, and changes in the Petroleum Regulations concerning the area fee, in a bid to promote an efficient exploitation of the petroleum resources on the Norwegian Continental Shelf.

The proposed changes in the area fee regime imply that no area fee should be paid in areas where exploration and production is undertaken. Areas where such activity is not satisfactory will be levied a higher fee.

The objective of the changes in the area fee regime is to contribute to a quick and efficient exploration of the Norwegian Continental Shelf. The aim for licensed areas is that either production activity or exploration activity should be carried out there. If sufficient activity is not carried out in the licences, the acreage should be assigned or relinquished so as to enable others to be given the opportunity to work with the same area with other ideas.

The Ministry is also submitting draft regulations for consultation regarding the use of facilities by others. The objective of these regulations is to achieve efficient use of existing facilities in order to ensure good incentives for licensees to undertake exploration and production, with a view to promoting efficient resource management. Such regulations will contribute to the above-mentioned objective by establishing a framework for the formulation of tariffs and other terms, thereby making the negotiating process more efficient. The commercial companies will still be the ones responsible for seeking good solutions for both parties.

# *Easing the tax burden on Russian oil*

Russia has put forward a new method of easing the tax burden on oil companies, according to *Novosti,* proposing tax regulations based on the quality of oil refining and the amount of refined oil. Economic Development and Trade Minister German Gref told the State Duma that the mineral production tax could be differentiated depending on the yield of oil wells, offering preferences for companies developing new deposits, and formulating measures to improve the quality of refined oil. He also outlined a proposal to introduce tax regulations on the quality and amount of oil refined.

Experts agree that tax preferences could make oil companies spend more on modernising technologies for oil production and refining. Analysts at Lukoil have estimated that a 15% increase in the quality and amount of oil refined will allow refiners to produce an additional 30mn tonnes of light oil products (gasoline, and diesel and jet engine oil).

According to Lukoil, Russia lags far behind Western countries in the production of light oil products. Of the 185mn tonnes of oil processed yearly, only 15.6% is turned into gasoline (in the US it is 43.3% and, in EU countries, 22.9%).

# Providence acquires UK interests

Providence Resources reports that, as part of an international consortium, it has acquired a 10% interest in the West Lennox discovery and the adjoining Crosby exploration prospect, both located in the Liverpool Bay area offshore the UK.

The West Lennox field is an unappraised oil discovery located in block UK110/14c. The nearby BHP-Billiton operated Lennox reservoir is currently producing 20,000 b/d of oil from block UK110/15a. Estimates of recoverable reserves for West Lennox range from 1.6mn boe to more than 3mn boe. First oil from West Lennox is expected at the end of 3Q2006.

In addition to West Lennox, the consortium has also acquired an interest in neighbouring block UK110/14d, which contains the highly prospective Crosby oil/gas prospect, with potential recoverable reserves of 15mn boe.

Furthermore, Providence Resources was recently awarded a 25% interest in northern North Sea block 210/19(p) as part of the UK's 23rd Seaward Licensing Round. Its partners in the block are Midmar Energy (55%, operator) and Sosina Exploration (20%).

***ExxonMobil has said that its flagship*** *deepwater oil field offshore Nigeria – Erha – will begin production in March 2006, writes* Stella Zenkovich. *Located in oil prospecting licence (OPL) 209, the field is being developed at a cost of $2.6bn.*

***Angola is planning to launch a*** *licensing round later this year, which will include seven blocks – 1, 5 and 6, located on the shelf of the lower Congo and Kwanza basins; blocks 15, 17 and 18 (excluding development areas) in the deepwater lower Congo basin; and block 26, a deepwater block in the Benguela sub-basin.*

***The New Nigeria Development*** *Company (NNDC) has signed a memorandum of understanding (MoU) with Energeum Petroleum to commence oil exploration in the Lake Chad Basin and Benue Trough, writes* Stella Zenkovich.

***Legal authorities in the island state of*** *Sao Tome have discovered 'serious irregularities' in the attribution of oil prospecting blocks in an offshore zone shared with Nigeria, a US consultant to the government said recently, reports* Stella Zenkovich. *The blocks were allocated for a total of $283mn to be shared 60:40 between Nigeria and Sao Tome. A US-registered Nigerian-funded company, EHRC Energy, was the main beneficiary, with shares in each block ranging from 15% to 65%.*

***Gaz de France has signed a produc****tion-sharing concession agreement with the Egyptian Ministry of Petroleum and the state-owned Egyptian Natural Gas Holding Company (EGAS) for the entire West El Burullus exploration block in the Mediterranean Sea, off the coast of Alexandria. Although GdF already holds a 20% interest in the North West Damietta block, this latest agreement will be its first operatorship in Egypt.*

***Eni has acquired from Nigerian compa****nies Allied Energy Resources and Camac International a 40% stake in Oil Mining Leases (OML) 120 and 121, located offshore Nigeria. Eni already operates the fields through its subsidiary Nigerian Agip Exploration (NAE). The Oyo field, one of the first oil discoveries made in the Nigerian deepwater during the previous exploration phase, is located in OML 120. Drilling is to start on the first well by end 2005. Two further appraisal wells have been scheduled during 2006 to verify the potential of OML 120 and 121.*

# Maximising North Sea reserves

With crude oil and natural gas prices continuing to dominate the headlines amid calls for additional investment in global oil production and refining capacity, UK oil and gas producers are playing their part and investing hard in the mature North Sea to maximise recovery of the country's reserves, estimated to be up to 28bn barrels. But the industry's efforts to stem the rate of UK production decline would be derailed by further tax hits, poor regulation and escalating costs. This was the message delivered by Malcolm Webb, Chief Executive of the UK Offshore Operators Association (UKOOA), at a fringe meeting at the Liberal Democrat Party Conference on 19 September 2005.

He said: 'Last week the Chancellor called for additional investment in oil production. UK oil and gas producers are already doing just that. Exploration of the UK Continental Shelf for new fields is up this year, as is the number of new production wells drilled to date. The industry invested over £8bn last year. This year, we expect that figure to rise by as much as 25% to £10bn.'

'The industry's efforts to stem the rate of UK production decline are paying off and current investment plans will see the rate halved to 7%/y. This means we expect UK fields to be producing for decades to come, and in 2020 should still be meeting 65% of all our oil needs and a quarter of our gas needs.'

'If we don't produce it, we will have to import it. Producing our own oil and gas saves this country £30bn on its balance of trade and will generate more than £10bn in tax for the Treasury, more than double the amount paid last year. Not only does it provide a secure source of primary energy, but is also supports over a quarter of a million jobs across the UK.'

'This industry has invested a total of over £330bn since the first exploration licences were issued more than 40 years ago. It has recovered 34bn barrels of oil and gas from Britain's often hostile offshore environment, risking not one penny of taxpayers' money but, on the contrary, earning this country more than £200bn in tax revenues in total. Furthermore, UK gas fields have supported the expansion of direct gas usage and gas-fired power stations in the UK, which have been the major contributor to the UK meeting its Kyoto targets.'

'The next chapter in the industry's history is now being developed on the already considerable presence of UK expertise, goods and services in the world energy market, which can continue to grow and create wealth for many decades yet to come. We should therefore be doing everything possible to build on and sustain one of the UK's most remarkable post-war industrial success stories. The country's reliance on oil and gas is growing, and government forecasts suggest that, by 2020, 85% of our primary energy needs will be met by these resources.'

'Yet I fear that we are still in danger of overlooking the significance of this great UK industry, which must not be put at risk from poor regulation, escalating costs and further tax hits. These would undermine investor confidence and erode international competitiveness – the very factors that will determine how long we can continue to produce economically from the North Sea.'

# *Talisman adds to Northern Alberta output*

**Talisman Energy plans to add upwards of 35mn cf/d of production from the Northern Alberta Foothills area over the next 14 months. This forecast is based on six wells that have already tested and are waiting to be tied in. In the Narraway area, one well tested at 19mn cf/d and three others tested at rates between 7mn and 12mn cf/d each. Two wells in the Grande Cache area tested at approximately 15mn cf/d each. Talisman's working interest in these wells ranges between 50% and 68%. Talisman plans to drill 10 additional wells in the area by the end of 2006.**

**The Northern Alberta Foothills is a new core exploration and development area, mid-way between Talisman's successful structural plays in north-eastern British Columbia and the Central Alberta Foothills. Talisman is the largest mineral rights holder in the area, having an average 56% working interest in 345,600 gross acres.**

**Talisman and its co-venturers have sanctioned and commenced construction of the Lynx pipeline system, which will act as the main trunk system for the Grande Cache area. The system, extending from the Findley area (east of Grande Cache) north-west through the heart of the trend, will consist of 72 km of 12-inch line and will have an initial raw gas capacity of 130mn cf/d.**

**Talisman is also planning the Palliser pipeline system, which will connect wells in the northernmost part of the Narraway trend to existing pipelines that move gas into British Columbia. The Palliser system will have an initial raw gas capacity of 45mn cf/d. Start-up is also planned for 4Q2006.**

# IN BRIEF

## EUROPE

***The Finance Corporation (IFC) of the*** *World Bank is to lend $12mn to Turkey's Palmet Metal Endüstri ve Ticaret to help expand the gas distribution activities of two subsidiaries, while setting aside $5mn for future concessions, reports* Keith Nuthall.

## NORTH AMERICA

***Suncor Energy Products, EHN Wind*** *Power Canada and Enbridge are reported to have received approval from the Alberta Energy and Utilities Board (EUB) to build a 30-MW wind power project near Taber, Alberta. The $60mn Chin Chute wind power project is expected to be commissioned in late 2006.*

***Chevron has closed the sale of*** *Northrock Resources to Pogo Producing Company for approximately $1.7bn.*

## MIDDLE EAST

***A major new private-sector regional*** *gas company – Dana Gas – is soon to be launched in Sharjah, reports* Stella Zenkovich. *The core founders of the new company are Crescent Petroleum and the shareholders of Sajaa Gas and United Gas Transmissions Company.*

***Technip of France has signed a $4bn*** *engineering, procurement and construction (EPC) contract for trains 6 and 7 of the RasGas III project in Qatar. Each train will have a 7.8mn t/y capacity, with production primarily targeted at the US market. Train 6 is slated for start-up in late 2008, with train 7 to follow in 2009.*

***The governments of Egypt, Jordan,*** *Syria and Lebanon – the Arab Gas Pipeline partners – have agreed to let Iraq join the Arab Gas Pipeline grid so that it can export gas to Europe by the end of this decade, reports* Stella Zenkovich. *Iraq has already agreed to export gas to Kuwait.*

## RUSSIA/CENTRAL ASIA

***Lukoil Overseas Holding has made a*** *$2bn offer to acquire 100% of the share capital of Nelson Resources, which is involved in development of the Alibekmola, Kozhasai, Karakuduk, North Buzachi and Arman field in west Kazakhstan. Nelson Resources is also a participant on two exploration blocks*

# NEWS



## Supertankers caught on canvas

**Young French artist Stephane Joannes will be holding an exhibition devoted to supertankers at Stephanie Hoppen's gallery in Chelsea, London, from 8–30 November 2005. The canvasses depict the vast vessels dominating the horizon and contain a wealth of carefully described detail. For more information, t: +44 (0)7589 3678 or visit** www.stephaniehoppen.com

## Energy trends in the UK

The UK government has published its latest (September) *Energy Trends* and *Quarterly Energy Prices* publications, which cover statistics on energy production and consumption, in total and by fuel, and provides an analysis of the year-on-year changes.

The reports indicate that indigenous production of primary fuels was 55.4mn tonnes of oil equivalent (toe) in 2Q2005, 7.5% lower than in 2Q2004, while final energy consumption in the period was 0.2% lower. Coal and other solid fuel consumption fell by 0.5% in the period, oil consumption fell by 6.3% and gas consumption fell by 4.3%. Primary electricity consumption increased by 6.7%.

Total indigenous UK production of crude oil and NGLs (natural gas liquids) in the second quarter of 2005 decreased by 10.1% compared with 2004, down to 21.9mn tonnes. Eight new fields came onstream after June 2004, but production from these fields was insufficient to make up for the general decline in output from older established fields.

The UK retained its position as a net exporter of oil and oil products. Exports of petroleum products fell by 4.8% in the period, while imports rose by 9.9%.

Total indigenous UK production of natural gas in 2Q2005 was 5.4% lower than in the corresponding quarter a year earlier. Compared with 2Q2004, exports of natural gas in 2Q2005 decreased by 26.2%, while imports increased by 53.6%. Net exports of gas at 7.4 TWh were 74.5% lower than in 2Q2004. Demand for gas in the second quarter of 2005 was 1.8% higher.

*Energy Trends* and the *Quarterly Energy Prices* bulletins can be viewed at **www.dti.gov.uk/energy/inform/energy_stats_overview/index.shtml**

## Rosneft to snap up Yukos asset

Rosneft is soon to become the co-owner of the East Siberian Oil and Gas Company (VSNK) in which Yukos holds a controlling stake of 70.77%, reports *Novosti.* VSNK holds a licence for the Yurubcheno-Tokhomskoye field in Evenkia, with recoverable reserves of 160mn tonnes of oil. Its development is at an early stage, but in 10 years it may yield up to 20mn t/y of oil.

Yukos cannot make the investment it has undertaken under the development contract due to the huge back tax bill the company has been hit with, and the regional administration has begun looking for a new partner. There are two ways for Rosneft to become a shareholder of VSNK – it can purchase a 28.5% stake in Yukos's production unit from Unikor management company or it can use Yukos' share. The embattled Yukos's assets have been frozen, which means they cannot be bought out directly.

However, Rosneft will probably not have to spend any money. The Courts have confirmed that Yukos owes the state-owned company as much as $2.6bn. Rosneft may seize Yukos's most attractive assets, including a stake in VSNK, as debt repayment.

*in the Kazakh sector of the Caspian Sea – South Zhambai and South Zaburunye.*

***Mitsui OSK Lines and Itochu Corporation*** *are reported to have signed a memorandum of understanding (MoU) with Gazprom to investigate the shipping of up to 15mn t/y of LNG from northern Russia to the US. Gazprom intends to have the Shtockman field, off Murmansk, feeding into a liquefaction plant by 2010.*

### LATIN AMERICA

***Brazil's state-run National Development*** *Bank is reported to have signed a $205mn financing contract (69% of the total investment) for construction of what is claimed will be the largest wind power farm in Latin America. The farm will be located in the south-western state of Rio Grande do Sul, and will be built by Vientos del Sur Energia, a joint venture formed by the Spanish firm Enervento, Germany's Enercon and CIP Brazil.*

### AFRICA

***Eni and Algeria's Sonatrach have set*** *up Transmed, a new joint-owned company to commercialise additional natural gas capacity carried through pipelines owned by Transmediterranean Pipeline Company (TMPC). The creation of Transmed follows an earlier agreement signed in May between Eni and Sonatrach, which established the expansion of the Trans Tunisian Pipeline Company (TTPC) pipeline. The agreement will increase annual transport capacity to Italy by up to 3.2bn cm, starting from 2008.*

***Centurion Energy International (75%)*** *is reportedly planning to expand its Egyptian gas sales by developing two new exploration concessions – West Manzala and West Qantara – which comprise 800,000 acres surrounding Centurion's discoveries in the El Wastani and South Manzala production leases. The company plans to deliver an additional 50,000 boe/d of natural gas and associated liquids by the end of 2007.*

***Amec has secured a gas pipeline engi-*** *neering, procurement and construction (EPC) contract in Yemen with its partner Hawk International. The two-year contract, worth more than $200mn (Amec's share 55%) has been awarded by Yemen LNG, a subsidiary of Total. The pipeline will carry gas from a field close to the town of Marib to an LNG terminal being built close to Bal Haf in the Gulf of Aden.*



# Latest European Union developments

**The first formal votes have been held on the European Union's (EU) proposed chemical control system REACH, with amendments being passed by the European Parliament's environment committee that will generally make life more difficult for petrochemical producers, writes *Keith Nuthall*. MEPs rejected the idea of a light touch for materials produced only in small quantities of between one to 10 tonnes. Also, the committee approved an amendment saying petrochemicals deemed potentially harmful be approved for only five years and then be subject to further testing. A November plenary meeting of the parliament will decide whether these changes survive, pending agreement with the EU Council of Ministers.**

**In other EU news:**

- **Transport Commissioner Jacques Barrot is to lead another European Commission attempt to harmonise fuel excise duty rates across Europe, with an initiative focusing on diesel sold to commercial vehicles. Barrot told an EU Council of Ministers for transport that his officials were 'currently preparing a proposal' setting maximum and minimum rates for diesel duty paid by commercial road transport companies. He is also developing a regulation mandating 'price review clauses in transport contracts in order to take into account variations in the price of fuel'.**

  **Curiously, however, the Industry Commissioner, Günter Verheugen, has announced that the Commission is dropping a similar proposal made in 2002, namely a directive 'to introduce special tax arrangements for diesel fuel used for commercial purposes and to align the excise duties on petrol and diesel fuel'. Brussels is also abandoning 2001 proposals to cut excise duty on biofuels and mineral oils containing biofuels, under a rationalisation of EU law-making. Both proposals have failed to secure agreement from MEPs and European ministers.**
- **EU Industry Commissioner Günter Verheugen has told MEPs he will use the CARS 21 high-level group promoting innovation in the automobile sector to boost the use of alternative low-$CO_2$ (carbon dioxide) fuels. Meanwhile, European Environment Agency (EEA) Executive Director Jacqueline McGlade has said hybrid vehicles are the only realistic short-term solution for reducing $CO_2$ transport emissions.**
- **The latest EEA data shows the combined penetration of low and zero-sulphur fuels increased from around 20% to almost 50% between 2002 and 2003, albeit some way off the EU target of 100% this year. The penetration of biofuels and other alternative fuels is low, with biofuel use in the EU less than 0.4% – way below Brussels' 2% target for 2005.**
- **The European Court of Justice's Court of First Instance has approved the European Commission's blocking of a proposed acquisition of Gás de Portugal (GdP), the country's gas utility, by electricity producer Energias de Portugal (EdP) and Italian energy company Eni. Brussels has ruled the deal would significantly harm competition, and the court has rejected a bid by EdP to reverse the decision.**
- **The European Investment Bank is planning to lend Britain's National Grid up to £120mn to help it expand an existing LNG import terminal on the Isle of Grain, Kent.**
- **The European Parliament has criticised the five-point-plan issued by Energy Commissioner Andris Piebalgs to deal with high oil prices because it failed to consider transport issues.**

# Statkraft's first Finnmark wind farm

Statkraft is reportedly planning to build a wind farm on Mount Gartefjell, south of Kjøllefjord in Lebesby – the company's first wind farm in Finnmark. The farm will have a total installed capacity of 40 MW and an annual output of some 155 GWh – enough to supply some 6,000 households with electricity.

The Kjøllefjord wind farm is Statkraft's fourth large-scale wind power project. The first was Phase 1 of the Smøla wind farm (40 MW), opened in autumn 2002, followed by the Hitra wind farm (55 MW), opened in October 2004. Phase 2 of Smøla (+110 MW) will be commissioned on 27 September 2005.

Once the Kjøllefjord plant comes onstream next autumn, Statkraft's wind farms will have a total output of some 750 GWh – equivalent to the electricity consumption of 37,500 households. Statkraft will then be well on its way to achieving its goal of producing 2 TWh/y of wind power by 2010, which will meet the electricity demands of some 100,000 households.

### UK

***BP is to sell Innovene, its olefins, deriv-*** *atives and refining group, to UK-based INEOS for $9bn. The sale includes all Innovene's manufacturing sites, markets and technologies. The company has 18mn t/y of petrochemicals capacity and 412,000 b/d of crude oil refining capacity.*

***Tesco is reportedly planning to acquire*** *21 supermarket forecourt sites from its rival Morrison. The deal will make Tesco the number one supermarket fuel retailer in terms of number of sites, with about one-third of the UK's supermarket based forecourts.*

***UKPX, the London-based energy*** *exchange for APX Group, and New Values, a Dutch-based emissions exchange, have signed a memorandum of understanding to launch a cleared spot carbon contract. The contract will be offered as part of the European Union Emissions Trading Scheme (EU ETS) by the end of the year.*

### EUROPE

***Centrica – through Segebel, a holding*** *company owned 50:50 in a joint venture with Gaz de France – has completed the acquisition of a controlling 51% stake in SPE, a Belgian energy company, in a deal which values SPE at 760mn (£515mn). At the same time, Centrica's existing 50:50 joint venture energy supply business in Belgium, Luminus, and ALG Nègoce, Gaz de France's 50:50 retail joint venture in Belgium, have been acquired by SPE for shares, valuing the entities at 207mn (£140mn) and 2mn (£1.4mn) respectively. The 49% balance of the enlarged SPE is held by existing Belgian shareholders of SPE, Publilum (Centrica's existing partner in Luminus) and ALG.*

***Germany's E.ON – Europe's largest listed*** *utility – is reported to be buying gas producer Caledonia Oil and Gas for £468mn ( 690mn), including debt, to boost its own gas reserves. Analysts report the acquisition of Caledonia will help E.ON reach its target of procuring up to one-fifth of its gas needs from its own fields. Caledonia holds interests in 15 gas fields in the UK sector of the southern North Sea. Its gas reserves are about 14bn cm, equivalent to the annual gas consumption of about 9mn households.*

***Supply chain management services*** *specialist Wincanton is to acquire the principal French operations of Premium*

# High octane bioethanol fuel


**Greenergy is planning to start marketing a new 'super fuel' at more than 100 Tesco forecourts across London and the south-east of England by mid-November. The super unleaded fuel is claimed to deliver the highest octane (RON) – 99 – of any fuel currently available to UK motorists, as well as providing environmental and enhanced engine cleaning benefits. 'It is the market's best value, performance enhancing fuel,' states Greenergy. The company goes on to claim that Shell Optimax is believed to have a maximum 98 octane rating, with BP's Ultimate fuel having a 97 octane rating and Esso's Energy Supreme unleaded 97.**

**The fuel – which is typically blended with 5% bioethanol – made its first race appearance as the power behind car number 73 in the Wales Rally GB Rally 2005. The Subaru Impreza was driven by Nigel Griffiths with Greenergy Chairman Andrew Owens as co-driver.**

# *Green power from organic waste*

The City of Millbrae, California, and Chevron Energy Solutions (Chevron ES), a unit of Chevron, have announced that they are starting construction of facilities at Millbrae's Water Pollution Control Plant (WPCP) that will generate on-site electricity from restaurant kitchen grease and other organic matter. The upgrades to the WPCP will make it one of the first wastewater treatment plants in the US to receive and process inedible grease in a comprehensive system specifically designed to control odours, generate reliable power, reduce energy costs and provide a new municipal revenue stream.

The new system will create and use a free biofuel – digester gas produced from grease – and will increase the amount of 'green power' currently generated by the facility's cogeneration plant by 40%. 'Because the system will generate electricity on-site, the city will avoid having to purchase about 1.5mn kWh from the local utility each year,' comments Chevron ES. 'This lower demand translates to 1,178,000 fewer pounds of carbon dioxide emissions annually, equivalent to planting 166 acres of trees.'

# Centrica boosts power portfolio

Centrica has boosted its power generation portfolio by increasing its interest from 60% to 100% in Humber Power, which owns the gas-fired, 1,260-MW South Humber Bank power station in North Lincolnshire. Centrica will make a cash payment of £46.5mn to Chanter Petroleum, a subsidiary of Total.

With the remaining 510 MW of Humber Power added to its existing generation fleet and the output from the fixed price element of its Spalding tolling agreement, Centrica will now be able to access approximately 4 GW of electricity output from its portfolio.

The deal is in line with Centrica's strategy of increasing the amount of gas and electricity it provides to British Gas customers from its own sources. Centrica already operates what is claimed to be the largest fleet of combined cycle gas turbine power stations in the UK and has invited tenders for the 1,010-MW Langage power station project in Devon, where it expects to make a final construction decision in the first half of 2006. It also completed its first coal-linked power purchase agreement earlier this year.

*Logistics for an initial debt-free consideration of approximately 24mn. The enlarged French business will operate from 29 sites across France.*

### EASTERN EUROPE

***OMV is understood to be planning to*** *acquire, for an undisclosed sum, 70 fuel retail outlets in the Czech Republic from BP. The deal will give OMV a total of 216 service stations in the country, doubling its current 10% share of the Czech fuel retail market and making it the largest fuel retailer in the country. Consumption of petroleum products in the Czech Republic, which last year was 8.2mn tonnes, is forecast to grow by 1.5%/y in the next five years, OMV said.*

***Shell and Turcas Petrol have signed an*** *agreement covering with the ownership, operation and management of a proposed 70:30 joint venture that will be engaged in retail, commercial fuels and lubricants marketing, and distribution activities in Turkey.*

### NORTH AMERICA

***Kerr-McGee has signed a purchase and*** *sale agreement with MarkWest Energy Partners for its non-operating interest in the Javelina gas processing and fractionation facility in Corpus Christi, Texas, for approximately $142mn. The Javelina facility is owned in partnership by Kerr-McGee (40%), El Paso Corporation. (40%, operator) and Valero Energy (20%).*

### MIDDLE EAST

***Foster Wheeler has secured a contract*** *from SABIC affiliate Eastern Petrochemical Company (SHARQ) for the engineering, procurement and construction (EPC) management of the complete utilities and offsite facilities to support the SHARQ 3rd Expansion Project at Al-Jubail, Saudi Arabia. SHARQ is a 50:50 joint venture between SABIC and SPDC, a Japanese consortium headed by Mitsubishi. This expansion project will add a total of 2.8mn t/y to production, including 1.3mn t/y of ethylene, 700,000 t/y of ethylene glycol, 400,000 t/y of linear low-density polyethylene, and 400,000 t/y of high-density polyethylene. Foster Wheeler has also been awarded a $112mn EPC contract by Bapco for a refinery gas desulphurisation project at its refinery located near Sitra, on the east coast of Bahrain. Bapco is wholly owned by the government of Bahrain.*



# *Refinery expansion plans in Brazil*

ConocoPhillips has signed a licence agreement with Petrobras for a grassroots 31,450 b/d delayed coking unit at its Pres Getúlio Vargas refinery (REPAR) in Araucaria, Paraná, Brazil. The terms of the agreement were not disclosed.

Part of a large-scale expansion project, the new coking unit will utilise ConocoPhillips' proprietary ThruPlus® delayed coking technology in order to increase the refinery's production of gasoline and diesel fuels as well as produce anode-grade, green petroleum coke. Start-up of the unit is slated for 2009.

REPAR, which has a total crude oil production capacity of 196,000 b/d, is responsible for approximately 12% of Brazil's national production of petroleum by-products, selling 85% of its products to the states of Paraná, Santa Catarina and Mato Grosso do Sul, in addition to the southern region of São Paulo. The remaining 15% is supplied to other regions of Brazil or is exported. Main products produced are LPG, gasoline, diesel fuel, fuel oils, jet fuel, asphalt and naphtha.

# Simon Storage sold to Inter Pipeline

**Simon Storage Ltd (SSL) – the UK's largest independent multi-site petroleum and petrochemical storage business, operating seven deepwater storage terminals on the UK and Ireland coasts, with a combined storage capacity of over 6mn barrels – is to be acquired by Inter Pipeline Fund for £120mn.**

**Inter Pipeline is a major Canadian petroleum transportation and natural gas liquids extraction business based in Calgary, Alberta, Canada. The company operates approximately 4,900 km of petroleum pipelines and 1.3mn barrels of storage in western Canada. These systems transport approximately 470,000 b/d of oil sands bitumen, conventional crude oils and gas plant condensate.**

**In addition, Inter Pipeline is one of North America's largest natural gas liquids extraction businesses with ownership in three major facilities located in southern Alberta. These facilities are capable of processing in excess of 6bn cf/d of natural gas.**

# *Shell Eco-Marathon Schools Initiative*

The Shell Eco-Marathon UK Schools Initiative (see *Petroleum Review*, September 2005) passed the half-way point in its selection process in mid-September, with 18 schools selected to take part in the programme. It was originally planned that 20 winning schools would be invited to take part. However, due to exceptional levels of interest, the programme has been extended to 30 schools.

The programme, which is supported by the Learning Grid, The Royal Academy of Engineering and Honda (UK), has been developed to encourage secondary schools throughout the UK to include engineering on the curriculum. The challenge for schools will be to design, build and compete with their own car in the Shell Eco-Marathon UK scheduled for 12–13 July 2006. The focus of the competition is improved energy efficiency, which is an investment focused firmly on the future and on sustainable energy resources. These students will be building the cars of the future.

# How green is your electricity?

UK electricity customers can now see for the first time how green their supplier is, as firms now have to show how much of their electricity is generated from renewable fuel under European Union legislation. Electricity suppliers must give their customers a breakdown of the fuels they've used to generate the electricity they provide, as well as the carbon dioxide ($CO_2$) emissions and radioactive waste produced.

UK Energy Minister Malcolm Wicks said: 'To help tackle global warming at an individual level, consumers need to make informed choices, and fuel disclosure is a key ingredient in helping people to do that. With a target of 10% of electricity generation from renewables by 2010, and an aspiration to get it to 20% by 2020, the disclosure rule is an asset to both domestic and business customers. Liberalised electricity markets give consumers a choice of supplier based on cost. From now, that choice will also be based on how the electricity was generated and the impact that has on the environment, so giving consumers even more choice in where their money goes.'

More information on the environmental impact of electricity supply can be found at **www.supplierenergy.co.uk**

## RUSSIA/CENTRAL ASIA

***TNK-BP has 'moderated' its fuel** prices at market levels prevailing in September in a bid to support the Russian government's efforts to ease up the tension in Russia's fuel retailing market. Pricing restrictions will stay valid till the end of 2005. The announcement followed Lukoil's earlier announcement that it was to freeze the retail price of petrol and diesel fuel at all its Russian service stations from 19 September 2005 until the end of the year. The company had already reduced fuel prices by 5% from December 2004 to May 2005. However, the initiative was not supported by other participants in the market at the time, claims Lukoil.*

## ASIA-PACIFIC

***Total (49%) has signed a second joint** venture agreement with Sinochem (51%) to set up a network of 300 service stations in the provinces of Jiangsu, Zhejiang and Shanghai in Eastern China, with a global investment of some \$100mn. The two companies have been partners for over a decade in one of the country's main refineries, located in Dalian, northern China, and in 2004 established a joint venture to set up a 200-strong network of fuel retail outlets in Beijing, Tinjin, Hebei and Liaoning provinces.*

## LATIN AMERICA

***Venezuela's state-owned oil company** PdVSA and Brazil's government oil company Petrobras are reported to have signed an agreement to build a new refinery in the north-eastern Brazilian state of Pernambuco at a cost of \$2.5bn. The new facility will process up to 200,000 b/d of heavy oil.*

## AFRICA

***The World Bank is reported to have** agreed to finance development of the \$400mn Bujagali electric power station on the River Nile in Uganda. Work is slated to start in July 2006.*

***BP is reported to be pulling out of** Kenya, selling its 50% stakes in three companies – Kenya Shell, BP Kenya and Shell & BP Malindi – that it owns jointly with Shell. The assets include 65 BP service stations and 17% of the oil major's share in Kenya Petroleum Refineries (KPRL).*

# Forecourt Watch in London


The Metropolitan Police has teamed up with forecourt security and crime reduction campaigner the British Oil Security Syndicate (BOSS) to roll out the Forecourt Watch scheme across eight London boroughs. Following the success of a scheme in Tower Hamlets, which was established two years ago and which has recorded a 50% reduction in crime, Forecourt Watch has been established in Brent, Ealing, Barking and Dagenham, Newham, Bromley and, most recently, Greenwich and Croydon. Hillingdon and Lambeth are expected to become members later this year.

The schemes are a welcome introduction as PC Ruari Robertson, Pan-London Forecourt Crime Reduction Adviser for the Metropolitan Police, explains: 'In 2003, over 32,000 people drove away from the capital's 700 forecourts, having committed various criminal offences and costing the industry millions of pounds. We now have 145 forecourts signed up to Forecourt Watch across eight boroughs and this sends a very clear message to would-be criminals – London is not the place to commit forecourt crime. Sophisticated systems are in place to allow forecourts to communicate with each other concerning incidents or suspicious incidences and each borough has a dedicated police officer to co-ordinate investigations and crime prevention.'

Criminals planning to target forecourts in the London area beware – a range of effective systems are in place for reporting and processing offences – which frequently lead to prompt results. For example, in the first month of the new Forecourt Watch scheme in Greenwich, a repeat offender was convicted and sentenced to five months' imprisonment for theft of petrol and driving whilst disqualified.

Forecourt Watch systems can include:

- ANPR (automatic number plate recognition) systems that identify 'vehicles of interest' via a centralised computer system that is regularly updated, allowing the police to track vehicles and investigate.
- Self reporting packs – for speed, efficiency and consistency, forecourt staff are trained to complete details of all offences as soon as they occur, including descriptions of suspects and car registration details. These are then submitted to police with copies of any CCTV tapes containing vital evidence.
- An effective protocol for dealing with incidents where a customer claims to have 'no means of payment' – leading to fast recovery of monies owed and identifying multiple offenders.

# New fuel catalyst cuts diesel fuel use

**Oxonica, a leading European nanotechnology company spun-out of the University of Oxford, has developed Envirox™ – a new fuel borne catalyst reported to reduce fuel consumption in diesel engines by up to 10% depending on the application. The catalyst is also claimed to reduce harmful particulate emissions by up to 15%.**

**The dose level of Envirox™ is very low because of its high activity; the catalyst concentration in diesel fuel is only 5 ppm. Oxonica estimates that if all HGV fleet operators in the UK were to convert to using Envirox™ in their engines, a reduction in diesel consumption in excess of 2.6mn b/y would result – equating to savings in excess of 1mn t/y of carbon dioxide equivalent.**

# Stepping on the gas

Photo: CNOOC

*Many Asia-Pacific countries are acutely aware of the need to diversify energy sources as oil prices hit record high levels,* writes Kim Jackson. *Gas is the key fuel of the future, with regional gas consumption (excluding India and Pakistan) forecast to grow from 292.2bn cm/y in 2000 to 2.44tn cm/y by 2050 – an eight-fold increase. Power generation is the primary driver of demand growth. By 2015, LNG demand from the power sector is likely to account for 70% of demand in Japan, 33% in South Korea, 75% in Taiwan, 60% in China and 45% in India.*

One of the key issues facing the Asia-Pacific gas markets is the effect that US LNG demand, especially on the west coast, will have on Pacific suppliers – particularly when China's and India's rising energy needs are taken into account. Indeed, China has experienced exceptional growth in energy demand in recent years – some 15.1% in 2004, according to the *BP Statistical Review of World Energy 2005*, while its economy grew 9.5%. Over the past three years Chinese energy demand has risen by 65%, accounting for over half the increase in global demand over the period. China now consumes 13.6% of the world's total energy. India, meanwhile, experienced a 7.2% increase in demand for energy in 2004.

More recently, the Asian Development Bank (ADB) stated that the Chinese and Indian economies will help pull the rest of Asia up to an average growth of 6.5% this year. However, it warned that surging oil prices – which reached $70/b in the wake of Hurricane Katrina – remain 'an uncertainty' and could impact growth projections. Robust growth in the US, signs of an economic recovery in Japan and projections for an economic rebound in the eurozone in the second half are also likely to cushion the impact of higher oil prices, the ADB said.

Some Asian economies are reported to have shown signs of a slowdown, for example in Thailand. However, the two largest economies in developing Asia – China and India – are showing no signs of a such a slowdown. The ADB had originally expected the Chinese economy to slow from 9.5% per annum to 8.5% this year – but this is now forecast at 9% or more. The Indian economy is projected to grow close to 7% this year, maintaining that pace in 2006 and 2007.

It should be noted that one reason why some Asian economies have been cushioned from the impact of soaring oil prices is that countries such as China, India and Indonesia heavily subsidise oil product prices, fuelling demand and keeping prices artificially lower. In contrast, Thailand, which scrapped oil subsidies this year, is feeling the effects of higher oil prices more than countries that have maintained subsidies, comments the ADB.

Meanwhile, as gas demand has risen, pipeline connectivity has evolved in the Asia-Pacific region. Until relatively recently there was only one international gas pipeline in this area – from Malaysia to Singapore. Now Singapore has two more links; from the West Natuna and from South Sumatra offshore gas fields in Indonesia, while Myanmar now exports to Thailand through its Yadana pipeline. India, Myanmar and Bangladesh have signed an agreement to set up a transnational natural gas pipeline from gas fields in Myanmar to India through Bangladesh's territory, although little progress has been made on the project since the agreement was signed. Further to the north, Russian LNG is to supply Asian markets, while Russian fields – which may lead to the development of long-distance pipelines into this region – are receiving growing attention from Asia-Pacific-based companies.

*(See also,* Petroleum Review, *May 2005 and September 2005)*

## BANGLADESH

*Photo: David Hayes*

**Many of Bangladesh's 3-wheeled taxis are run on CNG**

Bangladesh has made sound economic progress during the past decade, writes *David Hayes,* largely driven by the garment manufacturing industry, whose \$8bn/y of exports account for about 80% of foreign exchange earnings. The expansion of clothing production continues to drive economic development, which, in turn, has led to growing demand for commercial energy supplies.

While about 50% of Bangladesh's energy requirements are met by non-commercial energy sources such as wood, animal waste and agricultural waste, the government is encouraging development of potentially large indigenous commercial energy resources – mainly natural gas and coal.

Foreign investment is being sought to expand hydrocarbon exploration and development, and a number of foreign oil companies such as Unocal, Cairn Energy and Tullow Oil already are involved in natural gas production under production sharing arrangements with state-run Petrobangla.

Natural gas is Bangladesh's largest commercial energy source, accounting for about 66% of energy supplies. Recoverable gas reserves in producing gas fields total about 15.5tn cf – sufficient to meet current levels of domestic consumption until 2015. Exploration continues to discover additional reserves, with total proven and probable reserves in producing and non-producing gas fields currently put at 23tn cf.

In March 2005 Petrobangla announced that gas production had reached a record 1,450mn cf/d following the start-up of production from Unocal's Moulavi Bazar gas field in block 14, which produces 70mn cf/d and has reserves in the region of 440bn cf. Power generation for public supply and captive industrial use is the largest consumer of gas, accounting for about 45% of total gas consumption. Fertiliser production consumes about 22.5% of gas supplies, while other industrial consumers account for a further 15% and household customers the rest.

Industrial use of gas includes the production of CNG (compressed natural gas) as a vehicle fuel as part of efforts to limit petroleum product imports. More than 20,000 vehicles have been converted to use CNG to date, mostly in Dhaka, where many 3-wheeled taxis run on the fuel.

Although gas production in Bangladesh has risen most years for more than a decade, gas supplies are still insufficient to meet the power generation sector's fuel demand. Load shedding remains a problem in the capital Dhaka and other major industrial centres, as power stations are unable to meet overall electricity demand.

Although electricity consumption has grown by about 8.2% annually during the past 10 years, only 31% of the total population has access to electricity. About 25% of urban dwellers have access to power supplies, but the figure for rural areas is thought to be just 10%.

As part of efforts to increase electricity supplies and expand development of indigenous energy reserves, Petrobangla's mining division recently started up trial underground coal mining at Barapukuria in northern Bangladesh, with plans for full commercial mining operations in October 2005. Some 1mn t/y of coal will be produced to fuel a nearby 500-MW coal-fired power plant that will supply baseload power supplies to the Bangladesh national power grid. The Chinese government has provided funding for the power plant construction and to develop the coal mine. The power plant is expected to burn 830,000 t/y of coal, while Petrobangla will sell about 170,000 tonnes annually to other customers in the area.

The Barpukuria coal reserves total about 400mn tonnes. Petrobangla also plans to develop two other coal deposits, including one with sufficient reserves to produce 10mn t/y.

In other news, GAIL of India is reported to have offered to assist Petrobangla in bringing stranded gas from the offshore Kutubdia field to the market. Field reserves are not sufficient to make a dedicated pipeline commercially viable and GAIL has offered to provide full support and consultancy services to examine a number of alternative options, including the transport of CNG by ships and installing a gas turbine for power generation that could be transmitted by subsea cables.

India and Bangladesh are also reported to have agreed in principle on a tri-nation, 290-km gas pipeline project to pipe gas from offshore gas fields in Myanmar to India, via Bangladesh. If the pipeline goes ahead Bangladesh is expected to earn a \$100mn/y carrier fee.

## BRUNEI

*Photo: Shell*

**Sail away of the Champion West jacket**

Brunei is heavily dependent on oil and gas, which accounts for some 85% of the country's exports and an equivalent proportion of the government's revenues.

Brunei Shell Petroleum (BSP) – which dominates Brunei's oil sector – recently installed what is claimed to be one of the world's most advanced smart field platforms on Champion West, in 70 metres of water offshore Brunei. The reservoir is one of the largest undeveloped resources in the country and will support domestic oil and gas production for the next 20 years and beyond.

Dr Grahame Henderson, Managing

# Balancing supply and demand

*This table of data (below) referring to the Asia-Pacific region is abstracted from the latest* BP Statistical Review of World Energy, *June 2005, writes* Chris Skrebowski.

In terms of oil reserves, the only changes are the declines seen for India and Malaysia. In terms of oil production, large swings were seen, with a 13.9% fall in Australian production and a 4.5% fall in Indonesian production offset by a spectacular gain in Vietnam (+17.8%) and solid advances from Malaysia, China and India. The overall small production gain (+0.9%) meant that the region produced 9.88% of the world's crude, but consumed 29.03% of the world total.

Notable consumption gains were seen from China (+15.8%), Singapore (+12.4%) and Thailand (+9.2%), with solid gains from India, Bangladesh and Malaysia. Falls in consumption in Pakistan and Japan reduced the regional gain to 5.2%. This, however, was ahead of the global gain of 3.4%.

In terms of gas reserves, useful gains were seen in India and Myanmar, with smaller increases in Brunei, Pakistan and 'other Asia-Pacific'. The gain in Asia-Pacific reserves, which account for 7.92% of the global total, was only slightly less than the gain in global reserves.

Gas production advanced by 5% for the region, exactly the same gain as for global production. Notable production advances were seen from Vietnam, Pakistan, China, Bangladesh and Myanmar. In contrast, production in India and Brunei eased back, while, in New Zealand, it really fell away.

In terms of gas consumption, the region accounts for 13.67% of global demand and only slightly ahead of the 12% of global production that the region accounts for. There are large, intra-area movements of LNG from Indonesia and Malaysia to Japan, South Korea and Taiwan, but the region is only a small net importer of gas. Growth in gas consumption, at 6%, is nearly double the global rate of 3.3% and reflects the way that, once supply infrastructure is in place, economics within the region are able to increase the role of gas in the energy mix. China's 19% increase in gas consumption is a dramatic example.

In terms of refining capacity, the Asia-Pacific saw growth of 1.7%, with most of this coming from China (+6%) and India (+7.7%). The region accounts for 25.92% of global refining capacity and 27.46% of global refining throughput. This shows the pressure on the region's refineries and the high levels of utilisation. The sole exception is Japan, where refining capacity was trimmed slightly more than the decline in throughput. ●

Director of BSP said: 'This development brings together a number of cutting edge technologies, including very long horizontal "snake wells", downhole fibre-optic pressure and temperature sensors, and remote control using high bandwidth connections to the shoreline. It will allow engineers in BSP's Head Office to continuously monitor and improve the performance of the offshore wells and facilities, through a computer controlled system on the platform, which allows for remote well testing. The platform will be normally unmanned and only visited a few times per month by operators. The result will be improved reserve recovery and reduced development costs for this key asset.'

The platform and topsides were installed at the end of July 2005, with drilling of the wells expected to commence in October, followed by a second phase in the next few years.

A distinctive feature of the project was the extensive involvement of Brunei engineers from BSP, and local vendors and service providers. Both the subsurface jacket, and topside structure and facilities were constructed in BSP's fabrication facility at Kuala Belait. The topside was the largest ever constructed at the yard – weighing close to 1,200 tonnes.

Earlier in the year, BSP discovered oil in the Seria North Flank area. The company is planning to drill seven wells in the area by 2006. Discovered in 1929, the Seria field accounts for over 90% of Brunei oil production. Oil production peaked at more than 240,000 b/d in 1979, but has now fallen to below 220,000 b/d as the

| Country | Reserves (bn barrels) | Change 03/04 | R/P ratio (years) | Oil prodn (,000 b/d) | Growth 03/04 % | Oil consumpt (,000 b/d) | Growth 03/04 % | Gas reserves (tn cm) | Change 03/04 |
|---|---|---|---|---|---|---|---|---|---|
| Australia | 4.00 | n/c | 20.4 | 541 | –13.9 | 858 | 1.3 | 2.46 | n/c |
| Bangladesh | | | | | | 86 | 3.8 | 0.44 | n/c |
| Brunei | 1.10 | n/c | 13.6 | 211 | –1.5 | | | 0.34 | 0.1 decr |
| China | 17.10 | n/c | 13.4 | 3,490 | 2.9 | 6,684 | 15.8 | 2.23 | n/c |
| India | 5.60 | 0.1 decr | 18.6 | 819 | 2.8 | 2,555 | 5.5 | 0.92 | 0.7 incr |
| Indonesia | 4.70 | n/c | 11.5 | 1,126 | –4.5 | 1,150 | 1.4 | 2.56 | n/c |
| Japan | | | | | | 5,288 | –3.0 | * | |
| Malaysia | 4.30 | 0.3 decr | 12.9 | 912 | 3.6 | 504 | 5.2 | 2.46 | n/c |
| Myanmar | | | | | | | | 0.53 | 0.8 incr |
| New Zealand | | | | | | 151 | 2.2 | * | |
| Papua New Gu | | | | | | | | 0.43 | n/c |
| Pakistan | | | | | | 296 | –9.1 | 0.8 | 0.1 incr |
| Philippines | | | | | | 336 | 2.2 | * | |
| Singapore | | | | | | 748 | 12.4 | * | |
| South Korea | | | | | | 2,280 | –0.8 | * | |
| Taiwan | | | | | | 877 | 0.9 | * | |
| Thailand | 0.50 | n/c | 6.3 | 218 | –2.2 | 909 | 9.2 | 0.43 | n/c |
| Vietnam | 3.00 | n/c | 19 | 427 | 17.8 | | | 0.24 | n/c |
| Other Asia-Pacific | 0.90 | n/c | 13.2 | 184 | –5.1 | 411 | 6.6 | 0.38 | n/c |
| Total Asia-Pacific | 41.10 | 0.4 decr | 14.2 | 7,928 | 0.9 | 23,446 | 5.2 | 14.21 | 0.15 incr |
| Total World | 1,188.60 | 0.3 incr | 40.5 | 80,260 | 4.5 | 80,757 | 3.4 | 179.53 | 0.30 incr |
| Asia-Pacific as % | 3.46 | – | – | 9.88 | – | 29.03 | – | 7.92 | 0.32 incr |

**Table 1: Asia-Pacific production, consumption and refinery capacity, 2003–2004**
*Source:* BP Statistical Review, June 2005, *interpreted by* Petroleum Review; *Totals for countries not individually itemised; *included in 'Other Asia-Pacific'

country has cut output to extend the life of its oil fields and improve recovery rates. Brunei's crude reserves are currently put at 1.1bn barrels.

More recently, in September, Brunei opened the tender process for two onshore blocks – block L and block M. The closing date for bids is 3 January 2006. It is hoped that renewed exploration will help the country delay the onset of becoming a net oil importer. The country currently produces some 219,000 b/d of oil from Seria, from total reserves in the region of 1.1bn barrels.

Meanwhile, Brunei and Malaysia are reportedly making headway in talks to settle a territorial dispute over deepwater acreage that included blocks J and K off the coast of Borneo – although no timeframe for a final resolution has been indicated.

## CAMBODIA

Since *Petroleum Review*'s last Asia-Pacific review in November 2004, Chevron (55%, operator) has discovered oil in four exploration wells in block A offshore Cambodia. Oil pay logged in the wells ranges from 41 ft to 139 ft. Analysis of samples indicated that the oil is 44° API crude. John Watson, President of ChevronTexaco Overseas Petroleum, said at the time: 'The preliminary results of these exploration wells are promising... As a new exploration area for ChevronTexaco [now Chevron], Cambodia could offer the potential to build upon our already strong position in the Gulf of Thailand.' The drilling programme concluded with one more exploration well that was drilled in early 2005.

The other partners in block A are Moeco Cambodia (30%) and LG Caltex Oil (15%).

**Transport in Cambodia**

## CHINA

*(See also,* Petroleum Review, *May 2005 and July 2005)*

China has continued to see a widening gap between demand for and the domestic supply of oil as the country's economic growth has continued unabated. In August 2005, a government survey reported that Chinese demand for crude oil would rise about 6% from 2004 to 6.2mn b/d in 2005, while domestic crude production was predicted to rise by just 3%, to 3.6mn b/d – leaving a shortfall of 2.6mn b/d and implying a 6% increase from last year's average crude oil imports of 2.45mn b/d. China's crude imports rose 35% in 2004.

PetroChina is reportedly planning to spend up to 100bn yuan ($12.3bn) on expanding its network of oil and gas pipelines over the next five years in a bid to help meet soaring demand. Much of the proposed 15,000 km of new pipelines will be located in the south-west, north-west and north-east of China. Proposals are also understood to include a cross-border pipeline to transport oil to PetroChina refineries from Kazakhstan. Meanwhile, China is expected to begin filling its strategic oil reserve in 4Q2005 after work completes on 16 storage tanks at four sites in Zhejiang, Liaoning and Shandong provinces. The largest storage facility, at Zhenhai in Zhejiang province, will have a storage capacity of 5.2mn cm.

In order to help supply China's growing demand for both oil and gas, the country has been busy securing E&P interests overseas and signing key import deals in recent years. For example, Nigerian National Petroleum Corporation (NNPC) and Nigerian partner Equinox Energy have signed an $800mn, long-term oil supply agreement with PetroChina International,

| R/P ratio (years) | Gas prodn (bn cm) | Growth 03/04 % | Gas consumpt (bn cm) | Growth 03/04 % | Refinery cap (,000 b/d) | Growth 03/04 % | Refinery t'pt (,000 b/d) | Growth 03/04% |
|---|---|---|---|---|---|---|---|---|
| 69.9 | 35.20 | 6.20 | 24.50 | 1.10 | 864 | 0.2 | 804 | –2.30 |
| 33.0 | 13.20 | 7.00 | 13.20 | 7.00 | | | | |
| 28.3 | 12.10 | –2.00 | | | | | | |
| 54.7 | 40.80 | 18.50 | 39.00 | 19.00 | 5,818 | 6.0 | 5,469 | 13.40 |
| 31.3 | 29.40 | –1.70 | 32.10 | 7.10 | 2,513 | 7.7 | | |
| 34.9 | 73.30 | 0.70 | 33.70 | 0.80 | 1,056 | n/c | | |
| | | | 72.20 | –5.70 | 4,531 | –2.5 | 4,037 | –2.00 |
| 45.7 | 53.90 | 4.00 | 33.20 | 4.40 | | | | |
| 71.0 | 7.40 | 6.60 | | | | | | |
| | 3.60 | –13.80 | 3.60 | –13.80 | | | | |
| 100+ | | | | | | | | |
| 34.4 | 23.20 | 10.00 | 25.70 | 9.80 | | | | |
| | | | 2.50 | –7.70 | | | | |
| | | | 7.80 | 45.70 | 1,255 | n/c | | |
| | | | 31.60 | 17.40 | 2,598 | n/c | | |
| | | | 10.10 | 16.40 | 1,159 | n/c | | |
| 21.1 | 20.30 | 3.40 | 28.70 | 4.70 | 876 | 1.9 | | |
| 56.5 | 4.20 | 75.30 | | | | | | |
| 38.4 | 6.60 | –1.20 | 7.80 | 38.10 | 1,260 | –3.9 | 9,932 | 6.80 |
| 43.9 | 323.20 | 5.00 | 367.70 | 6.00 | 21,930 | 1.7 | 20,242 | |
| 66.7 | 2,691.60 | 5.00 | 2,689.30 | 3.30 | 84,592 | 0.8 | 73,710 | 3.40 |
| – | 12.01 | – | 13.67 | – | 25.92 | – | 27.46 | – |

under which China will be supplied with 30,000 b/d of Nigerian crude oil over a five-year period.

More recently, CNPC has signed a joint venture agreement with Uzbekneftegas, Lukoil Overseas, Petronas of Malaysia and Korea National Oil Corporation (KNOC) under which the companies will undertake E&P operations in the Uzbek part of the Aral Sea. The consortium is planning to sign a production sharing agreement (PSA) in 2006, after which seismic work will begin in the contract area. Over the last few years, eight gas condensate fields have been discovered in the Ustyurt region, which includes the contract area. Two of these – East Berdakh and Uchsay – have already been brought onstream.

In June, CNPC was reported to have acquired from Baraka Petroleum a 65% operating interest in block 20 in Mauritania's petrolific coastal basin. Under the terms of the agreement, the Chinese company will fund 100% of the exploration cost, up to $8.6mn. This will include a seismic acquisition programme over the Herron structure and the drilling of the planned Herron-1 well. Baraka will retain a 35% interest in the block.

China also has overseas E&P interests in and/or supply arrangements with Russia, Kazakhstan, Venezuela, Sudan, Iran, Iraq and Peru.

On a less positive note regarding overseas interests, however, CNOOC was earlier this year unsuccessful with its $18.5bn all-cash take-over bid for Unocal – the US' ninth-largest oil and gas producer – finally losing out to Chevron. Had CNOOC's offer been given the green light, it would have been be the largest-ever overseas acquisition by a Chinese firm.

Although keen to secure overseas supplies, China has continued its exploration and production programme on the home front, with CNOOC offering 10 offshore oil and gas blocks for exploration and development to foreign companies earlier this year. The blocks lie in Bohai Bay, the Yellow Sea, East China Sea and South China Sea, with water depths ranging from 10 to 200 metres.

Onshore western China is also reported to have 'large potential' for untapped hydrocarbon resources. For example, the Tarim basin of north-west China's Xinjiang Uygur Autonomous Region is thought to contain over 20bn tonnes of oil, while the Kela No 2 gas field in Xinjiang is reported to hold some 280bn cm of gas. The Puguang gas field in south-west China's Sichuan province is estimated to contain more than 100bn cm of gas, with the Ordos basin situated in the Inner Mongolia

**The Great Wall, China**

Autonomous Region holding some 200bn cm.

China is looking to not only discover new reserves, but also extend the life of its currently producing fields. For example, production resumed in mid-2005 from the Statoil-operated Lufeng field in the South China Sea, which was originally due to shut down for good in February 2004. New wells and innovative technology are expected to keep the development onstream from the *Munin* production ship until 2008. The field had been shut down for 11 months in order to drill sidetracks in three of the five existing production wells, and it began producing again on 9 June, later stabilising output at between 10,000 to 20,000 b/d. Statoil (75%) expects to boost the recovery factor on Lufeng from 32% to almost 40%. The field has yielded more than 37mn barrels since it came onstream in December 1997. At that time, the production forecast was just 25mn barrels. CNOOC is the remaining partner in Lufeng, holding 25%.

Projects to have come onstream over the past 12 months include CNOOC's 100% owned Luda (LD) 4-2 field in Bohai Bay, which came onstream in May, ahead of schedule, producing 5,600 b/d of oil from seven wells. LD 4-2, together with LD10-1 and LD 5-2, is located in central Liaodong Bay of Bohai Bay in about 100 ft of water, adjacent to the producing Suizhong 36-1 field. In September, CNOOC (83.8%, operator) announced that Bozhong (BZ) 25-1/25-1S came onstream, flowing in excess of 5,000 b/d from 17 wells, with a further 38 wells yet to be completed. BZ 25-1/BZ 25-1S is located in the south-eastern part of Bohai Bay. Development has been divided into two phases, the first of which commenced production in October 2004 – producing about 20,000 b/d from 79 wells via a single point mooring system (SPM), a floating production, storage and offloading facility (FPSO) and the B/E/D platforms. Phase 2 is designed to produce more than 15,000 b/d during peak production. The A platform is due to be commissioned in 2006.

More recently, CNOOC brought onstream its 100% owned Nanbao (NB) 35-2 in Bohai Bay, which is currently producing some 3,200 b/d from nine wells. After processing at the field's two platforms, the oil is transported to the QHD 32-6 FPSO for storage and sales. NB 35-2 production is expected to peak at 18,600 b/d.

Meanwhile, relations with Japan continue to be strained, with reports in mid-2005 of the Japanese government accusing China of 'siphoning gas' from its territory and demanding that CNOOC halt work at the Chunxiao field, which lies in the East China Sea between offshore Shanghai and the southern Japanese island of Okinawa. Relations between the two countries reached their lowest ebb in three decades when Tokyo stated in 2004 that it would allow exploration in the contested areas of the East China Sea. Japanese and Chinese officials continue to hold talks regarding the disputed area, but it seems unlikely that any breakthrough will be achieved soon. Indeed, in early September CNOOC was reportedly planning to start test production from the Chunxiao field, which it claims lies in Chinese waters, despite continued protests from Japan. The field is expected to flow at some 9mn cm/d. Meanwhile, Japan's Teikoku Oil was reported to have begun preliminary studies of drilling rigs and other equipment for an exploration programme in the disputed area of the East China Sea.

PetroChina and Shell announced in mid-2005 that they are jointly proceeding with the development of the Changbei natural gas field in Shaanxi province and Inner Mongolia Autonomous Region. The field is expected to start delivering 1.5bn cm/y of gas to markets in Beijing, Shandong, Hebei and Tianjin by 2007, rising to 3bn cm/y by 2008. Total development costs for the full lifecycle of the project will be about $600mn, covering the construction of the central processing facilities, inter-field pipelines and development drilling of about 50 horizontal and multilateral wells over 10 years.

Gas will play a key role in the future growth of China's economy, helping to plug the energy deficit. The country aims to raise natural gas to 8% of its energy mix by 2010, up from the current 3%. The country's main producing gas field at present is Jingbian, in north-west Shaanxi province, followed by the Kela-2 field, which is also in Xinjiang and lies adjacent to the new Dina field. Both fields are currently feeding in to the $8.5bn West-East pipeline. Gas sales via the pipeline are expected to rise to 4bn cm in 2005 – about one-tenth of China's total gas production. PetroChina was reported to have said in December 2004 that it aimed to raise sales to the full designed capacity of 12bn cm by 2007 – a year ahead of schedule.

A number of major gas projects are planned by CNOOC, including the country's first LNG import terminal in Guangdong province that will be supplied with 3mn t/y of LNG from Australia's North West Shelf project. Construction of a second terminal at Fujian is slated to begin in 2007, to be supplied with up to 2.6mn t/y of LNG from Indonesia's Tangguh LNG project. A third terminal is planned in Zheijiang province, and a fourth in Tianjin province.

CNOOC (45%) has also signed an agreement with Shenergy Group (55%) for the development of a 6mn t/y capacity LNG import terminal in Shanghai through the establishment of Shanghai LNG Company. Divided into two phases, the project is scheduled to start operation in 2008. Later in the year, CNOOC unveiled plans to develop a 2mn t/y LNG terminal on Hainan Island in southern China, the first phase of which is due for completion by 2009. Plans are to expand capacity to 5mn t/y by 2015. Initial imports will be supplied to power plants on Hainan; however, the planned expansion will allow the site to be used as a hub for further distribution. CNOOC is reportedly planning to set up 10 LNG terminals in total.

Renewable energy sources, including wind, solar power and thermal power, are to account for a larger share of China's energy resources under a new bill passed at the end of February. The new law, effective from 2006, orders power grid operators to purchase 'in full amounts' resources from registered renewable energy producers within their networks and encourages oil distribution companies to also sell biofuels. The law offers a number of financial incentives, such as a national fund to foster renewable energy development, and discounted lending and tax preferences for renewable energy projects.

In addition, China Power Investment Corporation (CPIC) was reported in July to be planning to build a total of ten 1,000-MW nuclear reactors on the eastern coast of Liaoning and Shandong provinces in a bid to reduce the country's reliance on coal. The Chinese government is understood to have set an ambitious target of building at least two new reactors a year. By 2020, 4% of the country's power needs will be supplied by nuclear energy, compared with 2% currently, from nine reactors in the Zhejiang and Guangdong provinces. Two further reactors are currently under construction in East China's Jiangsu province, bringing China's total capacity to about 9,000-MW.

Staying with renewable energies, China-based CMC International Tendering Corporation has contracted German company RWE SCHOTT to bring electricity to 26 villages in the remote Gansu province under the Chinese government's 'Brightness Programme', which is bringing electricity to extremely remote and currently unelectrified villages through the establishment of independent village 'minigrids'. These local grids will be powered by local hybrid diesel/solar power plants, 90% of whose energy output will be solar-based.

Looking at the downstream sector, ExxonMobil, Saudi Aramco and Sinopec earlier this year signed a $3.5bn deal to triple the capacity of a refinery in China's Fujian province to 12mn t/y (230,000 b/d) and add an 800,000 t/y ethylene cracker. Meanwhile, PetroChina was reported to be planning to spend $3.3bn to more than double refining capacity at Dushanzi Petrochemical in the north-western province of Xinjiang in order to meet rising demand for fuels and raw materials to make plastics. It is planned to increase capacity to 10mn t/y by 2008. China's consumption of petrochemicals is growing by 8–10%/y.

BP, Sinopec and Shanghai Petrochemical Company – the three parties in the SECCO joint venture – commissioned the SECCO petrochemicals complex in Shanghai. The 220-hectare facility, reportedly the largest petrochemical complex in China to date, was built in just 27 months, three months ahead of schedule. Commissioning of the 900,000-t/y cracker took just 10 hours and 45 minutes – a world record.

**Shanghai skyscrapers**

BP has also recently announced plans for a second world-scale PTA (purified terephthalic acid) plant at its BP Zhuhai site in Guangdong province, China. BP Zhuhai, a joint venture between BP (85%) and Fu Hua Group (15%), currently operates a 350,000 t/y PTA plant at the site and will also own and operate the new plant. The new plant, with a capacity of 900,000 t/y, will be the first to employ BP's latest generation PTA technology and, subject to final approval from the Chinese government, is expected to come onstream at the end of 2007. According to Steve Welch, BP Group Vice President, Aromatics and Acetyls: 'This investment will be the world's largest single train PTA plant, built in the world's largest and fastest growing PTA market with the world's best technology.'

Meanwhile, Castrol, the lubricant brand of BP, and Dong Feng Group unveiled plans to form a joint venture company to supply lubricants to the growing Chinese market. The new company, Dong Feng-Castrol Lubricant Co, will be based in Wuhan, in Hubei province, and is reportedly the first Chinese-based lubricant equity joint venture between a global lubricant major and a leading Chinese automobile manufacturer. Under the joint venture contract, BP, Dong Feng Motor Corporation and Dong Feng Automobile will have equity stakes of 50%, 20% and 30% in the venture, which will run for an initial 30-year period.

Staying with lubricants, the Shanghai Automotive Group Company (SAGC) and Shell are to launch a new joint venture to develop fast lube service facilities for motorists in China. The new joint venture – Anji Jiffy Lube Automotive Services Company – expects to develop about 10 pilot outlets in Shanghai within the first year of operation, using this experience to plan for expansion in Beijing and elsewhere in China. The outlets will be named 'Jiffy Lube Automotive Preventive Maintenance Centre' and will also display Jiffy Lube and Anji logos. Its lubricants products will be mainly provided by Shell. By 2015, the joint venture aims to have developed a network of more than 600 outlets across China and become a leading provider of automotive preventive maintenance services for the motorists in China.

The targets reflect the significant

# India – tackling the energy supply shortfall

The key energy challenge facing India today is preventing bottlenecks in energy supply from constraining economic growth, writes *Dr Parag Diwan*, Director and Chief Operating Officer of the Indian School of Petroleum, which recently announced a new partnership with the Energy Institute (see p50), and Vice Chancellor of UPES, Dehradun, India. The country is faced with debilitating oil import costs due to rising consumption and higher world oil prices.

India's energy supply shortfall has continued to grow since 1985, when the country became a net importer of coal. The country has been unable to raise its oil production substantially in the 1990s and rising oil demand of close to 10%/y has led to sizable oil import bills. In addition, the government subsidises refined oil product prices, thus compounding the overall monetary loss to the government.

India's rapidly growing economy is expected to drive energy demand growth at an annual rate of 4.6% through to 2010 – one of the highest incremental energy demand rates of any major country.

In 1995, coal accounted for 63.3% of India's primary energy production. In the same year, oil accounted for 18.6%, hydroelectricity 8.9%, natural gas 8.2% and nuclear power 1%. India's electricity is generated overwhelmingly by coal (70%). Hydroelectricity ranks a distant second (about 25%), followed by natural gas, nuclear power, oil and renewables, which account for the remaining 5%.

The current fuel mix is expected to change slightly in the period ending in 2010. Coal (65% of primary energy production) is projected to remain roughly the same as in 1995, while hydro (14%) and natural gas (10%) are forecast to have higher shares of total production. Oil production will decline sharply, however, to only a 9% share.

Overall, India's energy production was around 8.8 quadrillion BTu (quads) in 1995. By 2010, this is expected to reach 16.4 quads. In comparison, China's total energy production was 11.7 quads in 1970, 35.6 quads in 1995, and is forecast to rise to 64 quads by 2010.

Recently, the industrial sector has accounted for about half of India's energy consumption, while the expanding transportation sector and residential sectors have accounted for about 22% and 10%, respectively.

India's electricity demand has grown at an average annual rate of 8.8% since 1950. Annual capacity additions have not been able to keep up with demand, leading to power shortages and supply interruptions. As of 1995, almost 90% of the country was electrified, although much of the country continues to experience power disruptions.

Natural gas is India's most important potential alternative to coal. The Indian government is planning to make widespread use of natural gas in power generation and in the industrial and residential sectors. Projected demand will require large volumes of gas pipeline and liquefied natural gas (LNG) imports.

India's oil demand has risen to 1.6mn b/d, or more than twice domestic output. Almost half of India's trade deficit is due to petroleum imports, the cost of which also limits capital that could be invested in the economy. The government is hoping to restrain demand by gradually raising product prices to international levels.

India's heavy reliance on highly polluting coal makes development and installation of clean coal technology (CCT) a high priority. However, CCT is expensive to implement and questions have arisen on how to spread the costs of such technology.

India also plans to add to its current nuclear capacity of 1.7GW (see p19).

The Indian government has a long-term energy strategy that aims to:

- Increase utilisation of domestic energy resources by boosting oil production, reducing natural gas flaring and using coal production more efficiently.
- Improve the energy infrastructure by building new refineries, creating urban gas transmission and distribution networks, maximising efficiency of rail transport of coal and aggresively building new coal- and gas-fired power stations.
- De-regulate and privatise the energy sector, eliminating tariffs/subsidies on crude oil/refined products, de-controlling coal prices and making natural gas prices competitive, bringing power tariffs in line with international norms and gradually privatising the oil, coal and power sectors.
- Implement legislation to attract foreign investment, streamlining the approval process for private power producers, providing added incentives for upstream oil exploration and promoting mine-mouth power generation joint ventures.
- Utilise new technologies to increase energy efficiency.
- Reduce energy related urban atmospheric pollution.

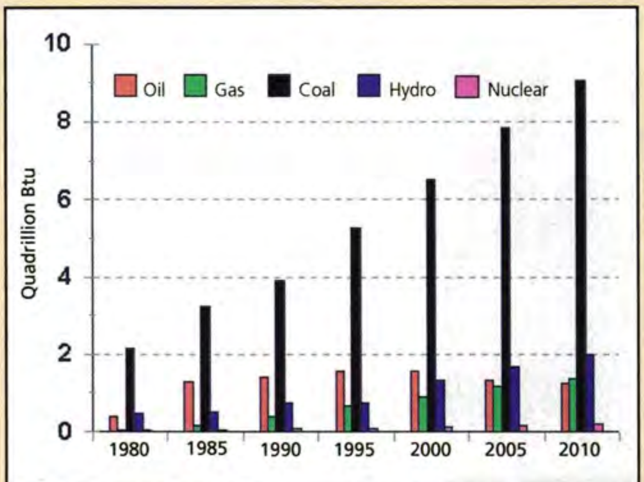


**Figure 1: Energy production by fuel**

*Source: US Energy Information Administration*

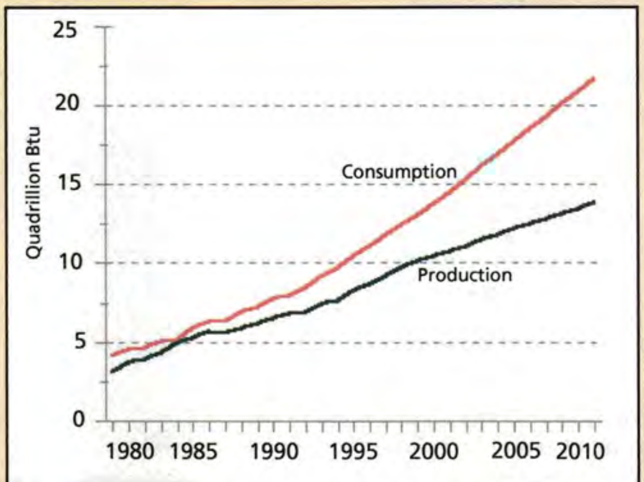


**Figure 2: India's energy balance**

*Source: US Energy Information Administration* growth in vehicle population in China, which already has 23mn vehicles on the road. In terms of new car sales each year, China is now the third largest in the world, after the US and Japan. The Chinese automotive after-sales market is also growing very rapidly as a result of the rapid increase in its car population.

## EAST TIMOR

**East Timor flag**

A total of 11 blocks have been offered off the coast of East Timor, together with four further blocks in its Joint Petroleum Development Area (JPDA) with Australia. Bidding is slated to end in mid-March 2006. A seismic survey conducted over East Timorese waters earlier this year is reported to have indicated some 20 to 30 potential prospects, although no reserve estimates have been released.

The JPDA blocks cover some 15,000 sq km. Under an agreement with the Australian government, any revenues generated will be split 90:10 in favour of East Timor. Earlier this year the East Timorese government established a Petroleum Fund Law to manage these oil revenues. The parliament has also passed final petroleum and fiscal regulations. Oil companies will be required to pay a royalty of 5% of gross output, a 30% tax on profits from the contractor's share of production and a profit-sharing scheme yielding 60% to the contractor and 40% to the state. East Timor also retains the right to acquire up to a 20% participating interest in any commercial discovery in the JPDA.

More recently, Santos announced plans to sell its 25% interest in the exploration permit JPDA 03-01 in the Timor Sea to Paladin Resources for \$19.5mn. In addition, Santos will be reimbursed for exploration expenditure in the permit between 1 July 2005 and completion of the transaction. This is expected to be approximately \$2.5mn. Santos will also receive \$3mn in cash under certain circumstances following any future oil field development in the permit. The permit contains the undeveloped Jahal and Kuda Tasi oil fields.

## INDIA

*(See also box p18)*

**India – not a rickshaw in sight...**

India's demand for oil and gas is forecast to double by 2020 as the country's economy grows rapidly at a rate of between 7% and 8%. India currently produces only half the natural gas it uses and imports 72% of the crude oil it needs. The Indian Petroleum Minister stated at the close of 2004 that India had oil reserves to last only until 2016 if no new discoveries were made and if production remained at 2001–2002 levels. As on 1 April 2004, recoverable oil plus oil equivalent of gas reserves were put at 1,658mn tonnes.

India's Directorate General of Hydrocarbons (DGH) recently unveiled plans to publish a quarterly performance report of drilling by firms operating in India in a bid to promote transparency in reporting finds and 'curtail the spread of speculative news'. The DGH stated that after making a find an operator should inform the management committee of that particular exploration block before making any formal announcements.

The Indian government earlier received a total of 69 bids for 20 exploration blocks under its fifth New Exploration Licensing Policy round (NELP V). These included bids from 26 foreign companies, including Cairn Energy, which, together with its joint venture partners, was awarded five new exploration blocks both on and offshore India, including two new areas in Rajasthan. Earlier in the year, Cairn received formal approval from the government for an 18-month extension of the exploration licence for further appraisal over 2,884 sq km of acreage in the north and west of Rajasthan. The appraisal area incorporates the Bhagyam and Shakti oil fields, as well as several structures requiring appraisal and intervening tracts of untested acreage. One such structure, N-I, has been successfully tested. Preliminary estimates for the field in-place volumes are between 35mn and 70mn barrels.

NELP V also saw the entry of Italian company Eni to the Indian sector, securing two operated exploration blocks – block 8 onshore Rajasthan and block D-6 in the deepwater Indian Ocean. Meanwhile, Niko Resources of Canada was awarded two blocks, securing a 100% working interest in onshore block CY-ONN-2003/1 in the Cauvery basin on the south-eastern coast of India. Together with partner Reliance Industries (operator), Niko was also awarded a 15% stake in deepwater block MN-DWN-2003/1 (D-4) located in the Mahanadi basin off the northern part of the east coast of India.

In other upstream news, in 1Q2005 INTEC Engineering's Kuala Lumpur office in Malaysia completed front-end engineering design (FEED) for state-owned ONGC's first deepwater field development offshore India in the Bay of Bengal. The field, located offshore the East Godavari region of Andhra Pradesh, is reportedly more complex than the conventional developments offshore India and much of the Far East, and, therefore, requires more thorough planning to facilitate the schedule, manage risk and to ensure system operability and safe performance for the life of the asset.

Planned for completion in 1Q2006, ONGC is developing its G1 field in the Krishna Godavari basin in close to 1,000 ft of water. While this water depth is not considered 'deepwater' compared to Gulf of Mexico activities, where asset developments can exceed 5,000 ft of water, the G1 development is a milestone for India as the country contemplates further deepwater developments.

The G1 project is part of an integrated development with additions to ONGC's GS15 field, also in the Krishna Godavari basin, and extensions to an existing onshore processing facility at Odalrevu. Both fields are part of ONGC's Rajahmundry asset. Anticipated peak production from the integrated development is 9,400 b/d of oil and 100mn cf/d of gas. The fields are expected to produce through 2015.

Meanwhile, Assam Company of India and Canada's Canoro Resources (operator) are reported to have started developing the Amguri block in Assam, India. Estimated in-place oil reserves are 58mn barrels, with associated and free gas reserves of 95bn cf.

Discoveries over the past year include Reliance Industries' 3.76tn cf of in-place gas reserves in two coal bed methane (CBM) blocks in the Sohagpur East and Sohagpur West blocks. The company plans to drill 20 more pilot wells to establish commercial viability of the two blocks. The company also made its 13th consecutive gas discovery in India, in the

D6 deepwater block off the Andhra Pradesh coast. The G-1 exploration well is understood to have flow tested on two intervals at rates close to 100mn cf/d. Reliance holds a 90% stake in the block, Canada's Niko holding the remainder. Nearly 14.5tn cf of gas reserves have been established in block D6. Reliance plans to produce between 40mn and 60mn cf/d of gas by 2007–2008.

In June, ONGC was reported to have made a significant gas find in the shallow waters of the Krishna Godavari basin off the Andhra Pradesh coast. The find was made on the GS-15 prospect, south-west of the Ravva field.

**...however, there are still plenty of traditional scenes**

Earlier this year, Shell Gas & Power announced the start-up of the Hazira LNG receiving terminal, located near Surat in the state of Gujarat in north-west India. The Hazira terminal received its first cargo on 17 April, which arrived from Australia's North West Shelf project in which Shell has a 22% stake. Hazira is a joint venture between Shell (74%) and Total (26%). The facility is capable of receiving up to 2.5mn t/y of LNG, although it has future expansion potential up to 10mn t/y

Meanwhile, GAIL and partners IOC and Bharat Petroleum finalised a $22bn deal with National Iranian Gas Export Company to supply 5mn t/y of Iranian LNG to India over a 25-year period beginning in 2009.

Looking downstream, Foster Wheeler has been awarded a project management services contract by ONGC for a grassroots facility associated with the removal of ethane, propane and butane from LNG that is to be constructed at Dahej, Gujarat. The LNG will be supplied from the nearby Petronet LNG receiving terminal. The new facility will initially be constructed with a single train of 5mn t/y capacity. Future expansion can be achieved by the addition of a second train. The project is scheduled for completion in 2007. The extracted products will be used as feedstock for ONGC's proposed petrochemical complex.

Earlier in the year, the Steel Authority of India signed an agreement with GAIL for the supply of 3.56mn cm/d of LNG to its steel plants in India, reportedly making it the first steel producer in the country to opt to use gas as an alternative to coking coal. The gas will be supplied via GAIL's proposed Jagdishpur-Haldia pipeline.

Meanwhile, Reliance Industries has unveiled plans to spend $5.7bn on doubling capacity at its Jamnagar plant in western India by 2H2009, to create what it claims will be 'the world's largest oil refinery'.

Moving to the renewables sector, UK-based biodiesel producer D1 Oils announced a significant boost to its alternative fuel programme in India, with D1 Mohan Bio Oils, its 50:50 joint venture, signing a memorandum of understanding (MoU) with the State Bank of India (SBI) to provide 1.3bn rupees (approximately £15mn) to local farmers in Tamil Nadu to plant up to 40,000 hectares of *jatropha*. The harvested seeds will have an anticipated yield of between 100,000 and 120,000 tonnes of crude *jatropha* oil per annum (assuming the full 40,000 hectares are planted). The costs of servicing the loans will be deducted from the price paid by D1 Mohan for the seeds.

D1 Mohan is a joint venture between D1 Oils and Mohan Breweries & Distilleries in India. In January this year, the company announced it would aim to plant up to 100,000 hectares of *jatropha* across India in 2005. The financing arrangements are a key component of this plan. D1 Oils has the option to export 25% of the unprocessed oil to its international customers, with the bulk of the unprocessed oil being retained for domestic biodiesel production. The use of bank finance to provide farmers with the ability to purchase seedlings and planting materials enables the business in India to expand more rapidly and conserve working capital.

Meanwhile, following clearance from the Atomic Energy Regulatory Board, India's first 540-MW pressurised heavy water reactor at Tarapur, near Mumbai, went critical in 1H2005. Unit 4 of the Tarapur nuclear power station is the flagship plant of the Nuclear Power Corporation of India.

More recently, the Indian government was reported to have unveiled plans to set up a 2,000-MW green field nuclear power plant at Jaitapur in Maharashtra and to expand three existing nuclear power plants, leading to the production of additional 6,000 MW of electricity. It is also understood to have given the go-ahead for new nuclear power plants to be constructed at Kakrapar in Gujarat, Kundankulam in Tamil Nadu, Jaitapur in Maharashtra and Rawatbhatta in Rajasthan.

## INDONESIA

Photo: David Hayes

**Ploughing a rice field, Indonesia**

Indonesia is the only Asia-Pacific nation to be a member of Opec, producing some 1.126mn b/d of oil from proven reserves of 4.7bn barrels, according to the latest *BP Statistical Review of World Energy*. However, the country is facing a steady decline (some 4.5%/y) in production as fields mature, a widening budget deficit and a weakening currency due to rising oil imports.

Indeed, shortly before going to press, President Susilo Bambang Yudhoyono announced that the government would be raising nationwide fuel prices from 1 October 2005 as part of its drive to cut fuel subsidies in response to the soaring cost of oil, which, it is feared, could send Indonesia's budget deficit spiraling out of control. The Indonesian Parliament had earlier agreed to cap the country's spending on fuel subsidies to 89.2tn rupiah ($892,000) for 2005. It also announced plans to give cash to millions of its poorest people to help them cope with the as yet unspecified fuel price rises. Some 60mn Indonesians, living in 15.5mn households, are expected to receive the 300,000 rupiah ($30) subsidy over three months.

A total of 13 blocks – located in the provinces of West Java, East Kalimantan, South Sumatra, North Sumatra, Lampung, East Java, Central Sulawesi and Papua New Guinea – were offered under Indonesia's latest licensing round. Only 11 of these blocks attracted 23 bids from 21 companies, with no company bidding on the north-east Madura V block in East Java or the Amborip V in the Arafura Sea. Winning bids included ConocoPhillips, who secured the right to explore the Amborip VI block, while local company PT Energi Timur Jauh, a subsidiary of the second largest local oil company PT Energi Mega Persada, got the East Kangean block in East Java.

In order to attract more investors, the Indonesian government is reported to have scrapped value-added taxes and import duties for all capital goods during exploration and production periods. It has also lowered its share of the oil output to between 65% and 80%, down from around 85% applied in previous contracts.

More recently, President Susilo Bambang Yudhoyono stated that the Indonesian government plans to pursue five policies to cope with the continued high price of crude oil. He outlined plans to increase oil production from 1.1mn b/d to 1.3mn b/d once the Cepu oil field in Central Java province and the Jeruk oil field in southern Madura island begin production. The second policy was diversification of energy, with Susilo calling on Indonesia to use new energy sources to substitute fuel oil, the production of which was declining. He also called on businesses to develop their uptake of renewable energy sources. Energy saving and conservation were also key.

The fourth policy was improving law enforcement, especially to combat fuel oil smuggling. The fifth policy was to reformulate the government's fuel oil subsidy policy as the current subsidy had yet to be enjoyed by low-income people.

The President further said that the government would continue to improve the investment climate in the oil and gas sector, develop good governance, and combat corruption. In addition, the government was also trying to maintain political stability by 'settling the Aceh and Papua conflicts in peaceful ways'.

State-owned Pertamina and ExxonMobil are understood to be close to signing a long-awaited deal on developing the above-mentioned Cepu oil field, which is thought to hold some 500mn to 600mn barrels of oil reserves and could add 180,000 b/d of production to Indonesia's declining output from 2008. It is reported that the contract period will be for 30 years, with Pertamina and ExxonMobil taking a 45% stake each, the Indonesian government holding the remaining 10%. To accommodate the deal with ExxonMobil, Indonesia is understood to have revised its upstream oil and gas regulations, under which the government could give exemptions on rules governing the state's participating interest, investment recovery and contract period.


**Mount Krakatau, Indonesia**

More recently, Indonesia's oil and gas regulatory body, BP Migas, was reported to have stated that ExxonMobil must develop the Natuna gas block in the South China Sea and find a buyer for the gas before the US company is entitled to a contract extension. The contract over the Natuna block expires in January 2006. It is understood that, of three operators in the Natuna block, ExxonMobil is the only one that has not begun development activities so far. The two others are Sea Energy and the UK's Premier. The block is estimated to hold reserves of some 40tn cf of natural gas.

In other upstream news, Australia's Santos made the biggest oil find in its 50-year history at the start of the year. The Jeruk discovery offshore Surabaya, Java, was reported at the time to 'have quelled concerns about the company's reliance on the declining fields of the Cooper basin in central Australia'. Recoverable reserves are thought to be in excess of 170mn barrels. Santos holds a 50% stake in the Sampang production sharing contract, the balance held by Indonesia's Medco, which last year bought Australia's Novus. Santos is also developing the Oyong oil and gas field, phase one of which is expected to produce around 8mn barrels of oil by the close of 2005. Phase two will be a gas development, with production expected by the end of 2006/early 2007.

Cooper Energy acquired a 45% interest in the onshore South Madura production sharing contract (PSC) in East Java, by buying a 50% stake in South Madura Exploration which holds a 90% interest in the PSC. Cooper is to pay 50% of the costs of an $8.9mn seismic and drilling programme over the area, which lies north of the Jeruk and Oyong oil and gas discoveries. Exsindo Petroleum holds the remaining 10% in the PSC.

Meanwhile, Pertamina is reported to be planning to explore further four wildcat wells in Java and Sumatra by the end of the year. Two of the gas wells are located in the Suban block in central Sumatra, the remaining two are located in Randu Blatung and Kedung Tuban, both in East Java.

Pertamina is also reportedly planning to restart oil production from 42 old wells as the current high oil price has made them economically viable once more. The company is also planning to develop seven wells in Sumatra, although no further details have been made available.

Meanwhile, Indonesia's largest independent E&P company Medco has unveiled plans to increase its exploration spending by $120mn in 2006. The company is looking to drill 40 new wells and to invest in oil exploration in Libya, where it was seeking to win at least four of 14 offshore oil blocks in the country. The company recently signed an exploration joint venture agreement with US independent Anadarko Petroleum. Under the agreement, Anadarko subsidiaries are gaining access to 13 production sharing contracts totalling 7.8mn acres onshore and offshore Sumatra, Kalimantan, Sulawesi, Java and Papua. Anadarko has committed to a 3-year work programme to fund exploration activities at a cost of $80mn. The company has the opportunity to earn up to a 40% interest in each production sharing contract where a successful exploration well is drilled at Anadarko's cost and a plan of development is approved.

Looking downstream, Indonesia is understood to be preparing to put out to tender Perusahaan Gas Negara's (PGN) proposed East Kalimantan to Java gas pipeline. The 1bn cf/d pipeline, which is slated to begin transporting gas to Java in 2009, is part of wider government plans to increase gas supply to the heavily populated, energy hungry island of Java to 3bn cf/d within the next four years. China's state-owned CNOOC and PGN are reported to have signed a memorandum of understanding to work together on the pipeline, while Chevron – which earlier this year bought out Unocal, which is active in the region – has offered to operate it.

Meanwhile, National Iranian Oil Company (NIOC) is reported to have signed an initial agreement to build a $3bn refinery in Indonesia, partnered by Pertamina. NIOC will take a 30% stake in the refinery, the location of which has yet to be decided. Indonesia currently imports about one-fifth of its oil products each year as its 1.083mn b/d of refining capacity isn't enough to meet domestic demand.

Moving to the renewables sector, the

Indonesian National Atomic Energy Agency (Batan) is reported to have proposed the construction of at least four nuclear power plants to cope with the growing power shortage problem in Indonesia. It is estimated that the plants will generate 4,000 MW of power that could supply 1.9% of the country's total electricity demand. The project is expected to begin in 2010 and to be commissioned in 2016. The first nuclear reactor is planned to be built in the Central Java town of Jepara.

## JAPAN

Photo: Saudi Aramco

**Saudi Aramco recently supplied its first LPG shipment to Japan's new Nanao LPG terminal**

Japan is almost totally dependent on imports to meet its energy needs, importing from its Asia-Pacific neighbours, as well as from Kazakhstan, Russia and the Middle East. Recent deals include an announcement that Russia's Sakhalin II project is to supply an additional 0.2mn t/y of LNG to Toho Gas Company for 20 years. The deal follows an earlier heads of agreement (HoA) that was signed in March 2004 for the supply of 0.3mn t/y of LNG to Toho. In addition to the increased volumes, Toho Gas has also decided to accelerate the start of LNG deliveries by one year to 2009. Gas deliveries will take place for a period of 24 years.

The project also recently signed a contract to supply 0.42mn t/y of LNG to Japan's Tohoku Electric Power for 20 years, from 2010. The deals bring the total number of agreements signed for LNG from the Sakhalin II project to eight.

Earlier in the year, the Russian government gave its final approval for a major oil pipeline to the Pacific. State oil pipeline monopoly Transneft is to build an 80mn t/y (1.6mn b/d) pipeline from Taishet in East Siberia to Perevoznaya Bay in the Pacific Primorsk region. The deal will enable Russian oil exports to both Japan and the US. Although this appears to rule out a direct route to China, it does not rule out China being supplied via a spur from the main pipeline. To supply both China and the Pacific would, however, require more reserves than have so far been proved up.

More recently, Saudi Aramco started exclusively supplying propane and butane to Japan's ambitious 1.5mn tonne national LPG stockpiling project. The very large gas carrier *Energy Orpheus* arrived on 19 August at the newly constructed Nanao LPG import terminal on the central Japan Sea coast to discharge 32,400 tonnes of propane and 12,000 tonnes of butane from Ras Tanura. It was the first shipment in the national LPG stockpiling project. Nanao, with a 250,000-tonne tank capacity, is the first in a series of five terminals planned to be finished by 2009. Japan's Ministry of Economy, Trade and Industry (METI) plans to secure 176,000 tonnes of LPG, the whole requirement for 2005, exclusively from Saudi Aramco.

Saudi Aramco has also strengthened its ties with Japan by taking a 9.96% strategic shareholding in Japanese company Showa Shell, increasing its total stake to 14.96%. It also recently signed an agreement to become a joint venture partner with Sumitomo Chemical in the development of a large, integrated refining and petrochemical complex in the Red Sea town of Rabigh, on the Kingdom's west coast. 'Once completed in late 2008, the Rabigh project will be one of the largest integrated refining and petrochemical projects ever to be built at one time,' according to Saudi Aramco. A total of 2.4mn tonnes of petrochemical solids and liquids, together with large volumes of gasoline and other refined products, will be produced.

## MALAYSIA

*(See also* Petroleum Review, *January 2005)*

Talisman Energy announced first oil production from the South Angsi field in block PM-305 offshore Malaysia in August, just 18 months after the field development plan was approved. In addition, a recent seismic survey has identified further exploration potential close to the South Angsi field, in block PM-314, and the company plans to drill a prospect before the close of 2005. South Angsi is expected to produce at a plateau rate of approximately 12,000 b/d (net Talisman share). Talisman Malaysia is operator, holding a 60% interest in blocks PM-305 and PM-314. The remaining 40% stake is held by Petronas.

Earlier, Aker Kvaerner announced the award of a contract by Murphy Sabah Oil for the engineering, procurement, construction and commissioning assistance of the subsea production systems for the Kikeh project. Kikeh, which is located in block K in approximately 1,350 metres water depth offshore

Photo: David Hayes

**Kota Baru market, Malaysia**

Sabah in eastern Malaysia, is operated by Murphy (80%) in partnership with Petronas (20%). It is the first deepwater development of its kind in the Asia-Pacific and is due onstream in 2H2007. Recoverable reserves are put at 400mn barrels. Technip of France is to install the field's Spar floating production platform – claimed to be the first one ever installed outside of the Gulf of Mexico and the first application of tender-assisted drilling on a Spar platform.

A recent arrival on the Malaysian E&P scene is Petrofac, which in 1H2005 awarded a contract to Global Process Systems (GPS) for the supply a mobile offshore production unit (MOPU) for the Cendor field in block PM304 offshore Peninsular Malaysia. Petrofac's partners on Cendor are Petronas, Kuwait Petroleum Exploration and PetroVietnam.

In early 2005 Petronas was reported to have discovered oil in the basement of an exploration well drilled within the southern Malay basin offshore Terengganu – understood to be the first such discovery in Malaysia. The Anding Utara-1 exploration well and its sidetrack both tested oil and gas in the basement, the bottom layer of a hydrocarbon prospect usually devoid of any potential. Anding Utara is located within the Malong-Sotong-Anding production sub-block of block PM12.

Meanwhile, Talisman (41.44%) was granted additional acreage to be included within the block PM-3 commercial arrangement area (CAA) offshore Malaysia and Vietnam, offering the potential for small field discoveries, which, if economical, can be quickly tied back to the existing PM-3 CAA facilities. The block currently contains six oil and gas fields, which comprise the PM-3 CAA Phase 2 & 3 project that is producing 60,000 b/d of oil and 270mn cf/d of gas. Petronas holds a 46.06% interest in the block, with PetroVietnam holding the remaining 12.5%.

Mutiara Petroleum, a 50:50 joint venture company between Petronas and Shell, has made a series of gas discoveries over the year in block PM301, off the north-east coast of Peninsular Malaysia. Bumi South-1 was the fourth discovery in the block, following the exploration successes of Bunga Kamelia, Bunga Zetung and Bunga Anggerik. The latest discovery is located about 25 km north-west of the Bunga Anggerik gas field discovered in November 2004.

Looking downstream, Petronas is reportedly planning to build a new terminal at Kimanis, capable of handling up to 300,000 b/d of oil and 1,250mn cf/d of gas from January 2010. The new terminal has been proposed as the existing crude oil terminal in Labuan and natural gas terminal in Kg Gayang have small production capacities and are unable to cope with production from the several deepwater oil and gas fields that have been discovered in the deepwater areas north-west of Sabah. Some 1.4bn barrels of oil and 7.7tn cf of gas have been discovered in Kamunsu, Kebabangan, Kikeh, Limbayong, Gamusut/Kakap, Malikai, Ubah Crest and Kinabalu since 2000.

Meanwhile, PICL, the international division of state-owned Petronas, has acquired a 4% shareholding in Centrica. Petronas is currently developing a 6bn cm/y LNG receiving terminal at Milford Haven, South Wales, UK, with BG and Petroplus. Petronas is also reportedly bidding to supply the entire 6mn t/y requirement of the CNOOC/Shenergy Shanghai LNG receiving terminal in China, due to open in 2008 with an initial capacity of 3mn t/y.

As reported earlier, Malaysia LNG (MLNG), a subsidiary of Petronas, is to supply Korea's Kogas with up to 2mn t/y of LNG for 20 years, beginning 2008, with an option to extend for another five years. The LNG will be supplied to Kogas from the Petronas LNG complex in Bintulu. The LNG will be transported to receiving terminals in Pyeong Taek, Incheon and Tong Young in South Korea by LNG vessels owned and operated by Malaysia International Shipping Corporation, a subsidiary of Petronas. The Petronas LNG complex in Bintulu is currently the world's largest integrated LNG facility at a single location, with a combined production capacity of approximately 23mn t/y.

MLNG has also signed a sale and purchase agreement (SPA) with Hiroshima Gas to supply up to 82,000 tonnes of LNG to the Japanese company for eight years, beginning in 2H2005. The deal increases MLNG's customer base among the Japanese power and gas companies to 12. The LNG will be supplied from the LNG complex in Bintulu, and will be delivered to Hiroshima Gas' receiving terminal at Hatsukaichi in Japan on ex-ship basis. Hiroshima Gas is the seventh largest city gas company in Japan in terms of gas sale, supplying primarily to the Hiroshima Prefecture. The company currently imports some 210,000 t/y of LNG from Indonesia.

The two companies have also signed a memorandum of agreement (MoA) with the City of Sendai that allows for the use of the LNG vessel *Aman Sendai* to deliver the LNG to Hiroshima Gas. The MoA is significant in that it is the first time that an LNG supplier and two customers have agreed to the mutual use of one dedicated vessel to transport LNG to the customers' respective receiving terminals.

In June, Petronas formalised a gas sales agreement with Keppel Energy of Singapore for the supply of up to 115mn cf/d of gas for a period of up to 18 years, commencing from middle of next year. This is the second supply contract to have been signed between Petronas and Singapore power companies. The first contract was signed in 1992 to supply 150mn cf/d of gas to Senoko Power for 15 years. In May, Petronas, through its subsidiary PC Muriah, signed a gas sales agreement (GSA) with Indonesia's state-owned electricity company, Perusahaan Listrik Negara (PLN). Under the terms of the GSA, Petronas will supply up to 145mn cf/d of gas to PLN's Tambak Lorok power plant in the Central Java province for a period of up to 10 years. The gas will be supplied from the Kepodang field within the Petronas-operated Muriah block.

## MALAYSIA-THAILAND JDA


**The Malaysia-Thailand JDA is a key piece of the energy jigsaw**

The Malaysia-Thailand Joint Development Area (JDA) is an economic zone located in the Gulf of Thailand, which was established to resolve the overlapping claims between the two countries over the area's hydrocarbon reserves. It is divided into three blocks – A18, B17 and C19, and is administered by the Malaysian-Thailand Joint Authority (MTJA).

In March, Amerada Hess reported that initial gas sales from block A18 had commenced. Gross production was averaging approximately 110mn cf/d, a level expected to increase to 390mn cf/d by 1Q2006. Amerada Hess and Petronas each own a 50% interest in the block A18 production sharing contract. Phase 2 natural gas sales, involving the delivery of an additional 400mn cf/d, will commence in 1H2008 for a 20-year period. Under Phase 3, the sellers' have an option to deliver additional natural gas volumes commencing between 2010 and 2012, subject to further drilling success on block A-18. Amerada Hess estimates that net production from block A-18 will exceed an average of 55mn cfe/d in 2005 and 140mn cfe/d in 2006.

Tenders are soon expected for engineering, procurement, construction and installation of platforms and pipelines for the development of Carigali-PTTEP Operating Company's (CPCO) block B-17 project, comprising the Muda and Jengka fields, due onstream in mid-2008. The development is expected to produce some 270mn cf/d of gas – although volumes could be raised to 470mn cf/d between 2010 and 2012 if more reserves are proven.

## NORTH KOREA

North Korea recently agreed to give up all nuclear activities and to rejoin international arms treaties in return for international help to create a peaceful nuclear energy programme. In return, the US, South Korea, Japan, China and Russia are reported to have expressed a willingness to provide oil, energy aid and security guarantees.

## PAKISTAN

Petronas of Malaysia commenced sales gas production from the Rehmat field in block 2769-4 (Mubarak) in Pakistan's Sindh province in 1H2005. The processed gas is supplied to Sui Northern Gas Pipeline's Sawan-Qadirpur trunk line. Initial production was 15mn cf/d, but rose to 70mn cf/d within months. Rehmat partners are Eni Pakistan and Pakistan's Government Holdings.

Meanwhile, Sui Southern Gas of Pakistan is reportedly planning to build an LNG import facility in either Karachi or Port Qasim in a bid to help meet rising gas demand in the country. It is looking to import between 2.5mn t/y and 3.5mn t/y, with Qatar and Iran likely sources.

## PAPUA NEW GUINEA

AGL of Australia was reported in June to have agreed a deal under which it will take $4.5bn worth of Papua New Guinea (PNG) gas – some 1,500 PJ – over the next 20 years to supply residential and industrial customers from Townsville to Melbourne. AGL will also take a 10% stake in the $3bn ($4.04bn) PNG phase of the project, which involves building a gas processing plant and a pipeline from the rugged Southern Highlands of PNG across the Torres Strait to Cape York. AGL will also lead a consortium to build a $2.5bn pipeline system linking Cape York to customers in Queensland and the Northern Territory and, later, Sydney and Melbourne.

It is hoped that the long-awaited PNG gas project will help reduce the country's dependence on foreign aid. Aid from Australia accounts for 30% of the PNG budget.

## PHILIPPINES

*(See also* Petroleum Review, *March 2005)*

**Philippine horse-drawn carriage**

The Philippines awarded an oil and gas exploration contract to Aragorn Power and Energy in early 2005, reportedly the first wholly-owned Philippine firm to be given such a licence in six years. Meanwhile, Malaysia's Petronas won rights to explore for oil and gas in Mindoro province.

At the close of 2004, the government awarded a contract to China's South Sea Petroleum Holdings to explore for oil and gas in the Agusan-Davao basin, while Japan Petroleum Exploration got a contract to explore over the Tanon Straits. Two other contracts were awarded in 2004 – one to Singapore-based Gas to Grid in the central Cebu area and the other to the UK's Premier Oil over the Ragay Gulf in the Bicol region and parts of the Bondoc Peninsula in Quezon province.

Looking downstream, D1 Oils announced an agreement between its subsidiary D1 Oils Asia Pacific and Atlas Consolidated Mining and Development Corporation, a leading Philippines mining and resource company. The two companies are to collaborate on a major project in the Philippines to rehabilitate land previously degraded by mining through the cultivation of *jatropha*, D1 Oils' feedstock of choice in the production of biodiesel.

President of the Philippines, Gloria Macapagal Arroyo, planted the first seedling at the project site in Toledo, Cebu Province. President Arroyo also supports D1 Oils' plans to intercrop *jatropha* on coconut plantations in the Philippines to help meet the government's targets for the use of biofuels.

The project will use bioremediation, a means of restoring soil that has suffered erosion and pollution in the mining process, by using *jatropha* to help replace lost nutrients. *Jatropha* was chosen not only due to its restorative qualities but also, and more importantly, because of its advantages as a biofuel feedstock. The first stage of the project is a five to seven hectare model farm and demonstration facility. The ultimate objective is to plant *jatropha* on 7,000 hectares of degraded land to produce fuel for power generation for off-grid mining facilities.

## SOUTH KOREA

Photo: KNOC/Amec

**Donghae-1 is South Korea's only producing gas field**

South Korea, Japan and China were recently reported to have proposed a 'Three Nation Joint-Oil Market' to 'actively engage in oil price determination and proper procurement process in the international oil community'. According to Hyundai Oil Bank President and CEO Seo Young-Tae, the three nations have been 'marginalised' in the oil pricing mechanism so far, regardless of the fact that the three countries have experienced huge demand growth for oil. He stated that the South Korean oil industry faced a number of problems, including government regulation, petrochemical sector depression, intense market competition, environmental regulation and a glut in petrochemical production.

Earlier in the year, Aminex and its wholly-owned subsidiary Korex were reported to have signed a nine-year production sharing agreement (PSA) covering Korea's West Sea offshore basin, part of the East Sea offshore basin, the onshore Anju basin, the onshore Jaeryong basin and the onshore Pyongyang basin. The company had previously announced an exclusive 20-year petroleum agreement with Korea in September 2004, under which it undertook to carry out certain work and provide technical assistance aimed at advancing petroleum exploration in the country. In exchange for carrying out this work, Aminex received rights to a royalty on hydrocarbons to be produced from any new drilling in the country by third parties, entitlement to a carried interest in any new wells drilled by other incoming companies and prior rights to apply for specific licences and explore in its own name anywhere in the contract area.

The Aminex PSA, which is made under Swiss law, is claimed to be far more comprehensive than any other exploration agreement previously signed in Korea. Intermittent exploration has taken place over a 30-year period and oil has already been discovered in the West Sea but never exploited due to lack of resources. The West Sea basin is adjacent to and thought to be an analogue of Bohai Bay, China's largest indigenous source of oil and gas and the scene of recent major discoveries.

In other upstream news, Woodside Energy and the Korea National Oil Corporation (KNOC) signed a joint study agreement to review the hydrocarbon potential of the Ulleung basin off the east coast of Korea. The basin lies immediately north of the Donghae-1 gas field – South Korea's only producing hydrocarbon project. With some 240bn cf of reserves, Donghae-1 is currently producing 50mn cf/d of gas – satisfying some 3% of South Korea's natural gas demand.

Korea is the second largest LNG market in the world, with Korean gas company Kogas the world's largest buyer of LNG. The company earlier this year selected Shell joint venture projects – Sakhalin II and Malaysia LNG – as suppliers of up to 4mn t/y of LNG to Korea over 20 years, beginning in 2008. It has also secured LNG supplies over the next four years from Qatar and Malaysia in deals that will meet some 8% of South Korea's demand until the end of 2008 (at 2004's consumption rate).

Kogas is also understood to be negotiating with five bidders for a combined 5.3mn tonnes of annual supply under long-term contracts to replace a long-term contract with Indonesia that is due to expire in 2007 and secure extra supply to meet rising demand starting from 2008.

Meanwhile, LG-Caltex is planning to build a new LNG receiving terminal near Kunsan, South Korea, for start-up in late 2007/early 2008. The company, which is looking to import 1.5mn t/y of LNG, is talking to suppliers in the Middle East and Asia with a view to setting up a 20-year contract.

Shipbuilding plays an important role in Korea's economy, with Daewoo Shipbuilding and Marine Engineering reported to have won new orders worth $350mn to build two LNG carriers – one to be supplied to Belgium's Exmar, the other to Maran Gas Maritime of Greece. Daewoo has also secured an option contract to build three more LNG regasification vessels for Exmar. Meanwhile, Chevron has ordered two LNG carriers from Samsung Heavy Industries to support the planned growth in the company's LNG business. The new LNG carriers will have a capacity of 154,800 cm each. Both carriers will be of membrane-type design and equipped with dual fuel diesel-electric propulsion. The two carriers are planned for delivery in 2009.

Looking downstream, South Korea's official oil refining capacity has been increased by 12.2% following a government refining industry reassessment study, writes *David Hayes*. The study revealed that four of the country's five oil refiners have constructed refineries with larger processing capacities than the companies had requested permission to construct and which the government had authorised.

The discovery of an additional 297,000 b/d refining capacity in excess of the previous official figure – equivalent to a decent size modern refinery – helps to explain the South Korean refining industry's recorded operating ratio of more than 100% from 2000 to 2004. The industry's operating capacity, it transpires, has been larger than its nominal refining capacity.

In spite of the undeclared refining capacity, the operating ratio for most Korean refineries has decreased over the past five years as domestic petroleum consumption has declined. The operating ratio grew a little in 2004, however, as petroleum exports grew last year, in particular diesel, which is the country's largest petroleum export.

South Korean refiners have not added any new capacity since 1998. According to Korea Petroleum Association, the government has decided to treat the discovery of undeclared extra refining capacity as additional capacity from debottlenecking, and none of the refiners are expected to face any punishment.

According to the results of the government reassessment, S-Oil (35% owned by Saudi Aramco) and Hyundai Oil (50% owned by IPIC of the United Arab Emirates) understated their actual refining capacity more than other companies. S-Oil's original topping capacity was stated at 443,000 b/d, but was discovered to be 580,000 b/d – an understatement of 137,000 b/d. Following the reassessment, S-Oil's operating ratio was recalculated at 116.5% – the highest of all Korean refiners.

**Incheon International Airport, South Korea**

Hyundai Oil's refining capacity was found to be 390,000 b/d, some 80,000 b/d more than the originally declared 310,000 b/d. Following the government reassessment, Hyundai's operating ratio became 87%, placing it fourth among Korean refiners. GS Caltex (formerly LG Caltex until being renamed in March 2005), was found to have 650,000 b/d of refining capacity, some 50,000 b/d more than the originally stated 600,000 b/d. Following the government reassessment, GS Caltex's operating ratio became 100.7%, placing the company second to S-Oil among Korean refiners.

Meanwhile, SK Corporation was found to have understated its refining capacity by 30,000 b/d. The company's topping capacity was increased to 840,000 b/d, up from 810,000 b/d following the reassessment, while the company's operating ratio was recalculated at 88.6%.

The only refiner unaffected by the government's reassessment is Inchon Oil Refinery. The company's topping capacity remains at 275,000 b/d, while the operating ratio is 37.1% as the court administered bankrupt company operates under a quota system. Inchon Oil is the country's smallest refiner. In September 2005, SK Corporation announced the signing of a MoU to acquire Inchon Oil in a deal that will result in SK owning more than 90% of the company's equity. As part of the deal, SK will pay out Korean won 800bn to 900bn ($780mn to $900mn) to the Inchon Oil creditors.

Meanwhile, South Korea's refining industry has reported improved results during the past 18 months due to increased exports and the development of the domestic chemical industry. All crude oil requirements are imported. In 2004 crude imports rose 2.6% to 825.8mn barrels, of which 78% was imported from the Middle East. Petroleum product exports grew 12.4% in 2004, to reach 235.4mn barrels – although still well below the 2001 peak of 306mn barrels. Diesel accounts for 28.9% of South Korea's petroleum exports, followed by Bunker C oil and jet fuel, which each represent 19.3%, and gasoline 7.8%.

China is the largest export market, taking 32.3% of exports, followed closely by Japan, taking 31.7%. Hong Kong accounts for 8.9% of exports, followed by the US taking 6.9%.

The rise in petroleum exports has helped offset a decline in domestic petroleum demand due to South Korea's economic downturn and changes in energy taxes. Petroleum consumption declined 1.4% in 2004 as rising oil prices encouraged greater use of imported natural gas for power generation and residential heating, replacing fuel oil consumption.

Gasoline consumption fell by 3.9% in 2004 as more people converted to diesel and LPG-fuelled vehicles. In July 2005, the government revised the fuel tax ratio governing the price of gasoline, diesel and LPG. The diesel fuel tax rose more than expected following complaints by non-government organisations (NGOs) over diesel pollution emissions, making LPG fuel cheaper and more attractive to use.

## SINGAPORE

Malaysia's KIC Oil & Gas is understood to have been given the go-ahead to develop a $340mn oil storage facility in Johor, close to Singapore. The terminal, which will offer 1.2mn cm of storage capacity as well as blending facilities, will be built on a man-made island close to Tanjung Pelepas and is due for start-up by 1Q2008. Some 70% of capacity will be used for domestic purposes.

Meanwhile, Oiltanking is reported to have commissioned a new jetty in Singapore to service its three terminals on Jurong Island. The $20mn jetty is capable of handling product tankers of up to 150,000 dwt and will help boost throughput at the terminal.

## SRI LANKA

It is reported that Sri Lanka's first bidding round, offering eight to nine blocks located in the Mannar basin for oil exploration, could be announced as *Petroleum Review* went to press. Norway's TGS Nopec has carried out seismic surveys over a 4,000-km stretch of seabed off Sri Lanka's western coast, which are understood to have shown evidence of hydrocarbon accumulations. Early studies pinpoint the Cauvery basin as having potential reserves in the region of 10mn to 50mn barrels.

Sri Lanka currently imports all of its 65,000 b/d oil requirements from Saudi Arabia, Malaysia and Iran – about two-thirds of that as crude and the balance as refined products. High oil prices lifted the country's oil bill to $1.2bn in 2004, up from the previous year's $800mn.

## TAIWAN

Photo: David Hayes

Taiwan traffic

Taiwan plans to increase the share of LNG, coal and renewable energy in its primary energy supply over the next 15 years, to substitute for a planned reduction in petroleum consumption, reports *David Hayes*. The natural gas share of primary energy supply will double and move LNG up into third place, ahead of nuclear energy, while the share of petroleum use will drop from 50% of total energy supply to the same level as coal. As a result, petroleum and coal will account for a combined 74% share of primary energy supplies.

According to Ministry of Economic Affairs forecasts, Taiwan's total energy consumption will increase 43.7% from 103.4mn kilolitres of oil equivalent (koe) in 2004 to reach 147.9mn koe in 2020 – recording a 2.1% average annual energy consumption growth rate over the 16-year period. The share of natural gas in the primary energy supply will double from 7% in 2004 to 14% in 2020, while coal's share will rise from 33% to 37% during the same period.

Renewable energy also will grow in importance, with its share of total primary energy supply forecast to rise from 1% to 4%. However, the petroleum share of primary energy will decline at the same time, dropping from 50% in 2004 to 37% in 2020.

Taiwan plans to double natural gas consumption over the next five years. Work is underway to construct state-run Chinese Petroleum Corporation's (CPC) second LNG import terminal as part of plans to expand clean energy use and increase security of supply as reliance on imported gas supplies continues to grow.

Construction is proceeding on schedule at Taichung harbour in central Taiwan, where the new receiving terminal is due for completion in mid-2007. Taichung LNG terminal will supply state-owned Taiwan Power Company's (Taipower) Tatan power station, which is currently under construction in the north of Taiwan. Tatan power plant is being built with six combined cycle blocks and will have a total installed generating capacity of 4,384 MW when the final unit is commissioned in 2010.

Taiwan consumed the equivalent of 6.8mn tonnes of LNG in 2004, of which 9% was indigenous gas production, equivalent to 612,000mn tonnes. Indigenous gas is produced in Miaol, in central Taiwan, and in some parts of southern Taiwan. Reserves are in decline and expected to run out in 10 to 15 years. Indonesia and Malaysia currently supply all LNG imports.

'We expect to supply 6.8mn tonnes in 2005 as we have no new customers this year,' commented a CPC source. 'In 2006 we hope gas sales will be about 7mn tonnes as we plan to start early supply for Tatan units 1 and 2.'

Power generation is the largest consumer of natural gas in Taiwan. In 2004 electricity generation accounted for 72% of CPC's gas supplies, while sales to industrial customers represented a further 15% of demand. Residential sales accounted for 12% of natural gas supply. Households are supplied by private city gas companies that distribute piped gas to most major urban areas in Taiwan.

Government plans call for gas use to almost double over the next five years and reach the equivalent of 13mn tonnes of LNG (including indigenous gas) by 2010. Electricity generation is planned to account for 80% of gas use, while industrial use will be 12% and residential use 8%.

Gas consumption will continue to expand over the following decade, but at half the rate targeted for 2006 to 2010. By 2020, the government expects Taiwan to use 16mn t/y of LNG, which is expected to consist entirely of LNG imports unless additional domestic gas reserves are discovered before then.

Meanwhile, Taiwan imports about 56mn t/y of coal, of which about 50.5mn tonnes is thermal coal for power plant and industrial use, while the steel industry imports about 5.5mn tonnes of coking coal. Taipower accounts for about 52% of Taiwan's thermal coal imports and consumption, purchasing 26mn tonnes in 2004, up 3.8% from 25mn tonnes in 2003. The state-run power utility expects to purchase almost 27mn tonnes of coal this year and will account for most of Taiwan's additional coal demand growth in the future.

Taipower's coal imports will rise again once the planned Jianping station starts up with two supercritical 600-MW units in 2011, followed by two more 600-MW units.

Formosa Plastics Corporation is the other major coal consumer, importing about 19mn tonnes of coal for its captive cogeneration and independent power producer (IPP) power plants. Apart from Taipower and Formosa Plastics, Hoping IPP plant burns about 3mn t/y of coal. The remaining 2mn tonnes are used by cement plants and other industries.

## THAILAND

3i, Europe's leading private equity and venture capital company, recently announced an $11mn investment in Salamander Energy, which currently holds a 9.5% interest in the Phu Horm gas field

**Downtown Bangkok**

in the north-east of Thailand as well as a 27.2% equity interest in exploration blocks L15/43 and L27/43 surrounding and offsetting the field. Partners in the Phu Horm field include operator Amerada Hess, ExxonMobil and PTT E&P. The net reserves attributable to Salamander are approximately 20mn boe (proved plus probable). First production from Phu Horm is scheduled for 4Q2006. Earlier in the year, Amerada Hess signed an agreement covering the sale of 500bn cf of gas from Phu Horm over a 15-year period. The gas will be purchased by PTT Public Company and delivered to the gas-fired power station at Nam Phong. First gas is expected to be delivered at an initial rate of approximately 80mn cf/d, increasing gradually to in excess of 100mn cf/d.

Meanwhile, Pogo Producing Company has closed its previously announced sale of Thailand assets to PTTEP Offshore Investment Company Limited and Mitsui Oil Exploration for $820mn. The proceeds are to be directed toward Pogo's pending acquisition of Northrock Resources, a wholly owned Canadian subsidiary of Unocal.

More recently, US company NuCoastal and partner PetroWorld Corporation were reportedly planning to submit development plans for the Bua Ban field in block G5/43 offshore Thailand following a successful drilling programme. Possible reserves have been put at 17mn barrels of oil and 2.34bn cf of gas.

Singapore-based Pearl Energy has produced first oil from the Jasmine field in block B5/27 at an initial rate of 2,000 b/d from three development wells.

At the close of 2004, Petronas unveiled plans to acquire Kuwait Petroleum (Thailand) (KPTL) from Kuwait Petroleum International, paving the way for the Malaysian oil company to further expand its presence in the retail and marketing sector of the Thai oil and gas industry. Under the terms of the sales and purchase agreement, Petronas took over KPTL's retail service station and lubricant businesses, including 117 operational service stations located in major cities in Thailand. About 70% of the stations are located in the Bangkok metropolitan area, while the rest are spread out in other areas of Chiangmai, Nakorn Rachasima and Pattaya. The acquisition did not include KPTL's aviation business, which was handed over to Kuwait Petroleum Aviation (Thailand).

Staying downstream, Thailand is accelerating the introduction of alternative fuels as part of attempts to reduce the cost of transportation, writes *David Hayes*. A sharp increase in the number of vehicles crowding the country's roads has raised petroleum product consumption, forcing the government to take steps to cut the Kingdom's soaring oil import bill.

Energy officials in September announced that Thailand will import about 18mn litres of ethanol this year following output cuts by domestic producers for various reasons. PTT, Thailand's largest oil and gas company, will import and distribute ethanol to all refineries to mix with gasoline to make gasohol.

Total ethanol demand from mid-September to the end of December is forecast at about 51.5mn litres as more motorists begin to use gasohol – which retails about 6% cheaper than 95-octane gasoline. Sales of gasohol containing 10% ethanol currently are around 2.5mn l/d and account for 24% of premium gasoline use compared with 8mn l/d of 95-octane fuel.

Gasohol was commercially launched two years ago in Thailand. Government plans call for gasohol sales to increase to 4mn l/d by the end of 2005 and to completely replace premium gasoline sales countrywide by 2007. The number of gasohol service stations is due to increase from about 730 at present to 4,000 eventually, as more service station chain operators start offering gasohol.

Other alternative transport fuels also are being promoted to reduce oil import costs. Oil imports grew 60% from 2000 to 2004 in value to reach 476bn baht (40.85 baht = US$1) and account for 86% of Thailand's total 555bn baht energy import bill, followed by gas imports from Myanmar that cost 49bn baht and represent 9% of the energy import cost.

The government has set up a pioneering biodiesel plant with a daily production capacity of 300,000 litres and has set a target of encouraging nationwide biodiesel consumption to grow to 8.5mn l/d by 2012.

Thailand's four oil refineries, with a combined capacity of 703,000 b/d, are sufficient to meet the country's domestic requirements. PTT had planned to merge its Rayong Refinery Co with Star Petroleum Refining, majority owned by Chevron. In mid-September PTT announced it had cancelled its merger plan due to disagreements about the listing of the enlarged US enterprise after its merger with Unocal.

PTT, meanwhile, continues to expand its natural gas business transmitting and distributing locally produced gas and piped gas imports from Myanmar. Thailand's electricity industry is 72% reliant on domestic and imported natural gas, while local lignite and coal account for 13% of electricity generation, and hydroelectricity 9%. Remaining power generation is produced by power plants burning Bunker C fuel oil and recycled fuel.

While Thailand will soon begin importing coal for power generation and some other uses to reduce over reliance on gas, PTT recently has announced plans to double its proposed 20bn baht investment to develop natural gas for vehicles (NGV) use to 40bn baht in response to the large unexpected public response to the launch of NGV (natural gas vehicle) filling stations.

In mid-September, about 6,600 vehicles used NGV fuel supplied through 36 PTT service stations. PTT originally planned to increase the number of its service stations selling NGV fuel to 260 in 2008. The number has recently been increased to 410 due to the sudden surge in public interest. The number of PTT service stations selling NGV fuel will increase to 150 at the end of 2006, rising to 270 in 2007.

PTT now forecasts that the number of vehicles using NGV fuel will increase to 70,000 by the end of 2006 and to 126,000 in 2007, rising further to 210,000 by the end of 2008.

Other service station operators also will offer NGV fuel. PTT has announced it will supply Bangchak Petroleum and Shell Company of Thailand with NGV fuel to sell at five service stations each as an initial trial run.

PTT's NGV fuel programme will require the company to build a number of new gas pipelines to supply gas to service stations in areas outside the company's current gas transmission grid coverage area. Gas pipelines will be built to supply gas from the Greater Bangkok grid area to areas in eastern and central eastern Thailand. In southern Thailand, gas supplies will be tapped from pipelines supplying power plants with gas from fields in the Gulf of Thailand to supply service station operators in the major cities, including Nakhon Si Thammarat, Surat Thani and Songkhla.

## VIETNAM

Vietnam's economic transformation since the early 1990s has brought important changes throughout many parts of the country as ties with former Soviet bloc countries have weakened while trade and investment links with the western world have blossomed, writes *David Hayes*.

Although still an agricultural nation with about 80% of the population working on the land, Vietnam's leading export earner is crude oil with annual earnings up 48% to \$5.7bn in 2004. As a net exporter of oil, recent high oil prices have contributed to Vietnam's bright macro-economic outlook, which has been buoyed by increased foreign investment, remittances and overseas development assistance, and good budget discipline.

Vietnam currently has 600mn barrels of proven oil reserves. Exploration contracts for about 30% of offshore geological shelves with hydrocarbon potential have been awarded to date, but there are others that the government still wants to explore. Exploration licence bidding was opened last year for the Phu Kanh basin, for which the deadline was extended to mid-2005.

Vietsovpetro, a joint venture comprising state-owned oil and gas monopoly Petrovietnam and the Russian External Economic Federation (Zarubezhneft), is Vietnam's largest oil producer, operating Bach Ho (White Tiger), the country's largest oil field. While the government has approved plans for Vietsovpetro to produce 10.5mn tonnes of crude this year, in January 2005 the government also announced that total oil production could fall to about 352,000 b/d in 2005 due to decreased output from Bach Ho and Su Tu Den (Black Tiger) oil field in a bid to extend the life of the fields.

In other news, Stolt Offshore is reported to have secured a \$36mn engineering, procurement, construction and installation (EPCI) contract from PetroVietnam for the Dai Hung extension project. The contract covers flowlines, risers, umbilicals and buoys and the tie-back of five new wells to the existing Dai Hung floating production unit in block 05-1a.

Meanwhile, invitations to tender are soon to be issued to companies that have prequalified for the Su Tu Vang (Golden Lion) project in block 15-1 in the Cuu Long basin offshore south Vietnam. The field came onstream in late 2003 and is currently producing to the 1mn barrel capacity *Cuu Long* FPSO. It is understood that further development will require a 10,000-tonne central processing platform, jacket and pipelines, due onstream in 2008.

Three further finds have been made in block 15-1 since the discovery of Su Tu Vang – including Su Tu Den Northeast and Su Tu Trang, appraisal of which is planned this year. The most recently discovered Su Tu Nau (Brown Lion) oil field is thought to hold some 120mn barrels of potential oil reserves. Tests are to continue to determine commercial viability of the field.

Photo: David Hayes

**Busy street in Ho Chi Minh City, Vietnam**

Block 15-1 partners are PetroVietnam (50%), ConocoPhillips (23.3%), KNOC (14.2%), SK Corporation (9%) and Geopetrol (3.5%).

Crude oil is a major contributor to economic growth. Oil production averaged a record 402,000 b/d in 2004, making Vietnam the third largest oil producer in Asia after Indonesia and Malaysia.

All oil produced is exported due to Vietnam's lack of refining facilities, with net oil exports totalling 193,000 b/d last year. Industry and consumer energy consumption, mainly for transport, are the major forces driving the growth of petroleum product use. Oil exports will remain unchanged in volume this year, according to the Ministry of Trade, which earlier announced that Vietnam plans to export 19.6mn tonnes of crude worth \$5.5bn in 2005.

Government plans to develop a domestic refining industry finally are due to go ahead. In May 2005, Petrovietnam, the state-owned oil and gas monopoly, awarded a foreign consortium led by Technip-Coflexip, the French oilfield services firm, a \$1.56bn engineering, procurement and construction (EPC) turnkey contract to build the country's long-delayed first oil refinery. The consortium, which also includes JGC Corporation of Japan, Technicas Reunidas of Spain and Technip Geoproduction of Malaysia, will build the main components of Dung Quat oil refinery, which will be capable of processing 130,000 b/d of crude.

Due for completion in February 2009, Dung Quat will have an annual processing capacity of 6.5mn tonnes of low sulphur crude oil. The refinery is likely to process 5.5mn t/y of oil from the offshore Bach Ho field, along with 1mn t/y of Middle East sour crude. Most of Dung Quat's output will be used to replace imports, although some may be exported. Products will include gasoline, jet fuel, kerosene, diesel, LPG and feedstock for propylene production.

Although the Vietnamese government decided to undertake the Dung Quat project alone rather than face continued delays while seeking other foreign partners, the search for additional foreign investors continues for the proposed Nghi Son refinery in northern Vietnam. Mitsubishi Corporation of Japan and SK Corporation of South Korea have declared support for the project, while a Russian-backed investor has proposed building a third refinery in the south, this time without Petrovietnam's involvement.

Meanwhile, Vietnam's natural gas industry is growing, supplying associated gas from the Bach Ho field and non-associated gas from the BP-operated Nam Con Son gas field. Most natural gas is supplied for power generation at present and fertiliser production. Future plans call for piped gas distribution systems to be built in the southern region, where industrial gas use is expected to increase.

The coal industry also is expanding, supplying a growing number of overseas customers, while domestic demand is forecast to grow in the future, mainly from new coal-fired power stations. By 2010 Vietnam is expected to burn 10.2 t/y of coal to fuel power plants totalling 3,745 MW installed capacity.

Vietnam's power generating capacity is forecast to more than double during the next five years to reach 20,650 MW in 2010. Gas-fired power plants totalling about 4,800MW will start up from 2005 to 2010, along with hydroelectric dams with an installed capacity of about 4,300 MW. Coal-fired electricity will be supplied mainly to Hanoi and the northern region, while gas-fired electricity will be distributed mainly to Ho Chin Minh City and other areas in the south.

| Country/Field | Operator | Disc. | Oil or gas output | Start-up date | Oil res. (mn b) | Gas res. (bn cf) | Capex ($mn) | Production system |
|---|---|---|---|---|---|---|---|---|
| **BANGLADESH** | | | | | | | | |
| Bangora-1 (block 9) | Tullow Oil | 2004 | gas disc | | | test 120mn cf/d | | |
| Bibiyana (block 12) | Unocal | 1998 | gas/cond | 4Q2006 | | 6,000 | 341 | onshore |
| Kutubia | PetroBangla | | gas | | | small | | |
| Moulavi Bazar (block 14) | Unocal | 1999 | gas | Mar-05 | | 440 | 70 | onshore |
| Shahbazpur | Unocal | 1995 | gas | 2006 | | 333 | | onshore |
| **BRUNEI** | | | | | | | | |
| Bugan | BSP | 1993 | gas | | | 140 | | |
| Champion West Ph1 | | | oil | Oct-05 | | | | |
| Egret Ph1 | BSP | 1971 | oil/gas | 2006 | 50 | 700 | | 12-slot platform |
| Kikeh (see Malaysia) | | | | | | | | |
| Mampak | BSP | 1997 | oil/gas | | | | | evaluation |
| Merpati | BSP | 1992 | gas | | | | | evaluation |
| Seria North Flank | BSP | 2004 | oil | incr reserves | +100 | | | |
| **CHINA** | | | | | | | | |
| Bajiaochang (Sichuan province) | Burlington Resources | | gas | go-ahead given | | | | |
| Bonan fields (Bohai Bay) | CNOOC | | oil/gas | Nov-04 | 30 | 300 | | |
| Bozhong 25-1 (Bohai Bay) | CNOOC | | hvy oil | Oct-04 | 350 | | | FPSO |
| Caofedian CFD 11-1, 11-2 | Kerr-McGee/CNOOC | 1999 | oil | Jul-04 | 130 | | | FPSO + 2 platforms |
| Caofedian CFD 11-3, 11-5 | Kerr-McGee/CNOOC | | | 2H2005 | | | | 4 horiz + NNM plat to FPSO |
| Caofedian CFD 11-6 | Kerr-McGee/CNOOC | | | planning | | | | tieback to FPSO |
| Caofedian CFD 12-1, 12-1S | Kerr-McGee/CNOOC | | | planning | | | | tieback to FPSO |
| Changbei (Ordos basin, Shaanxi province) | Shell | | gas | by 2007 | 2,500 | | 600 | onshore |
| Cheng Dao Xi (Bohai Bay) | Noble Energy | 1998 | oil | Feb-03 | 30 | | | platform 11 wells |
| Chuanyu | CNPC | | | expansion | | | | |
| Chuanzhong block (SW China) | Burlington Resources | | gas | 2005 | | 1,000 | | |
| Chunxiao (East China Sea) | CNOOC | | gas | Sep-05 | | | | under develop. Dispute with Japan |
| Daniudi (Inner Mongolia) | Sinopec | | gas | Jun-09 | | 8,800 | | pipeline to Shandong |
| Dina (Tarim basin) | CNPC | | gas/cond | end-2006 | | | | to feed East-West pipeline |
| Dongfang 1-1(S China Sea) | CNOOC | 1992 | gas | 2003 | | 1,750 | | |
| East China Sea fields | CNOOC | gas/cond | 2005 | 30 | 1,500 | | | |
| Erdos basin, Inner Mongolia | PetroChina | 2002 | gas | | | 21,268 | | |
| Futai (Shengli area) | Sinopec | 2000 | oil | | 160 | | | |
| Huizhou 19-1/2/3 fields (S China S) | CACT | 2000/2001 | oil | Nov-04 | 60 | | | 2 plats, 14 wells FPSO |
| Huizhou 21-1 (S China Sea) | CACT | 2000 | gas/cond | 2006 | 10 | 115 | | |
| Jinzhou 21-1 (Bohai Bay) | CNOOC | 2000 | oil/gas | 2008 | 7 | 60 | | |
| Kela-2 (Tarim basin) | | 1998 | gas | | | 10,000 | | feeds East-West pipeline |
| Luda 4-2 (Bohai Bay) | CNOOC | 2002 | hvy oil | May-05 | 90 | | | |
| Lufeng (restart of field) | Statoil | s/d 2/2004 | oil | Jun-05 | addnl 9 | | | subsea + FPSO |
| Luojiazhai (Sichuan)+3flds (Sichuan) | | 2002 | gas | 2005 | | 5,600 | | |
| Lungu (discovery in Tarim) | PetroChina | 2001 | hvy oil | | 500 | | | onshore |
| Mosuowan | PetroChina | | gas/oil | | 150 | | | |
| Nanbao 35-2 | CNOOC | 1996 | hvy oil | Jul-05 | 110 | | | 2 platforms to FPSO |
| Panyu 4-2/5-1 (S China Sea) | Devon Energy | 1998 | oil | Oct-03 | 90 | | | FPSO + 2 welhd plats |
| Panyu 19-3 1 | CNOOC | 2002 | gas | | | | | |
| Panyu 30-1 1, 34-1 1 | CNOOC | 2003 | gas | | | 1,500 | | |
| Pearl River Mouth fields | CNOOC | 2001/2003 | gas | 2006/2007 | | 1,500 | | |
| Peng Lai 19-3 (Bohai) Ph2 | ConocoPhillips blk 11-05 | 1999 | oil | 2007 | 800 | | 1,800 | multiple plats, central process |
| Puguang (SW of Sichuan province) | | 2004 | gas disc | | | 3,500 | | |
| Qikou 18-2 (Bohai Bay) | CNOOC | 1995/2000 | oil/gas | Jun-04 | 9 | 10 | | |
| Sulige (Ordos basin) | PetroChina | 2001 | gas | | | 11,800 | | |
| Tahe (Tarim basin) | Sinopec | | oil | | 10bn boe | | | production expansion |
| Tainan (Qaidam) | | | gas | | | 3,400 | | |
| Tarim basin 13 fields | | | gas | | | 13,200 | | |
| Tarim basin Kela 2 | | | gas | | | 10,000 | | |
| Weizhou 11-1 (Beibu Gulf) | CNOOC | 2004 | gas/oil | discovery | | | | |
| Weizhou 12-1 (Beibu Gulf) | CNOOC | 1999 | oil | Jun-04 | 30 | | | |
| Wenchang 8-3/19-1 | CNOOC | 1986/1994 | oil | 2005 | 40 | | | |
| Zhao Dong (Bohai Bay) | Apache/PetroChina | 1994 | oil | Aug-03 | | | | 2 platforms 17 wells |
| **INDIA** | | | | | | | | |
| Bombay Offshore | ONGC | 1974 | oil/gas | 1976 | 5,500 | 15,800 | | offshore |
| D6 (Krishna Godavari basin) | Reliance Industries | | gas | 2007/2008 | | 14,500 | | offshore |
| Dhirubhai (Krishna Godavari basin) | Reliance Industries | 2002 | gas | Mar-08 | | 7,000 | 2,573 | offshore |
| GS-15 (Krishna Godavari Basin) | ONGC | 2005 | gas | discovery | | | | 2 plaforms piped to shore |

Table 2: Current and planned key field developments in the Asia-Pacific region

| Country/Field | Operator | Disc. | Oil or gas output | Start-up date | Oil res. (mn b) | Gas res. (bn cf) | Capex ($mn) | Production system |
|---|---|---|---|---|---|---|---|---|
| G1 (Krishna Godavari basin) | ONGC | | oil | 1Q2006 | | | | 5 subsea wells to shore |
| Gauri | Cairn Energy | 2001 | oil/gas | 2004 | | 92 | 88 | platform t/bk to Lakshmi |
| Mangala (northern Rajasthan) | Cairn Energy | 2003 | oil | 4Q 2007 | 100–275 | | | |
| Aishwariya | Cairn Energy | Mar-04 | oil | 4Q 2007 | 130–470 | | | |
| NB | Cairn Energy | Feb-04 | oil | eval | 400 | | | tested 6,000 b/d |
| NC or NV | Cairn Energy | Apr-04 | oil | eval | 300 | | | |
| N-I | Cairn Energy | Jun-09 | oil | eval | 30–75 | | | |
| Orissa coast (Bay of Bengal) | Reliance Industries | Jun-04 | gas | discovery | | 4,000–5,000 | | |
| Panna & Mukta | BG-ONGC-Reliance | 1976 | oil/gas | 1986 | 180 | 550 | 751 | offshore |
| Panna expansion | BG-ONGC-Reliance | 1976 | oil/gas | 3Q2005 | 18 | 74 | | 2 wellhead plats, 11 horiz wells |
| PY-1 | Mosbacher Energy | 1980 | gas/cond | 2005 | | 230 | 97 | onshore platform |
| Raageshwari-5 (Rajastan basin) | Cairn Energy | 2005 | gas disc | | | | | |
| **INDONESIA** | | | | | | | | |
| Banyu Urip (Cepu block) | ExxonMobil | 2001 | oil/gas | 2005? | 600–1000 | | | platform +FSO |
| BD (Madura) | ExxonMobil | 1987 | gas/oil | 2005+ | 20 | 310 | | platform |
| Belanak (blk B West Natuna, S China Sea) | ConocoPhillips | 1975 | gas/oil | Dec-04 | 75.2 | 500 | | FPSO (100kb/d+gas) |
| Block A, North Sumatra | ConocoPhillips | | gas | 2005+ | | 476 | 240 | onshore to fertiliser plt |
| Cepu | ExxonMobil | | oil | | | 250 | | operator post 2010 negotiations |
| Donggi and Senoro (Sulawesi) | Pertamina/Medco Energi | 1999/2001 | gas | 2007+ | | 4,000 | | |
| Gajah Baru (New Elephant) | Premier Oil | 2000 | gas | 2005+ | | | | Natuna Sea, no sales contract |
| Gehem (offshore E Kalimantan) | Unocal | 2004 | gas | eval | | 1,500 | | joint development Ranggas |
| Gendalo Ph1 | Unocal/Eni | | gas | 2007 | | | | |
| Jabung (Makmur, N Geragai) | PetroChina | 1995/1996 | oil/gas | 2003 | | | | |
| Jeruk | Santos | 2005 | oil disc | | 170+ | | | |
| Kerisi | ConocoPhillips | 1990 | oil | 2005 | | | | |
| Merah Besar | Unocal | 1996 | oil/gas | 2005+ | 52 | 160 | | mini-TLP to West Seno |
| Natuna D Alpha | ExxonMobil | 1973 | gas | 2010+ | | 46,000 | | 16 platforms |
| Nubi/Sisi | Total | 1986/1992 | gas | 2007 | 40 | 2,700 | 200 | plat joint dev |
| Oyong Ph1 | Santos | 2001 | oil | late-2005 | 8 | | | |
| Oyong Ph2 | Santos | 2001 | gas | end 2006/2007 | | 90 | | |
| Ranggas (off Kalimantan) | Unocal | 2000 | oil | evaluation | 400 | 200–350mn boe | | joint development Gehem |
| Singa (S Sumatra) | Exspan | 1997 | gas | 2005+ | | 400 | | onshore |
| Sirasun/Terang | BP | | gas | 2005+ | – | 800 | 500 | subsea via Pagerungam |
| Sungai Kenawang | Repsol/YPF | 2002 | gas/cond | | | | | test 380,000 cm/d, 370 b/d |
| Tangguh (Weriagah) | BP | 1990–1997 | gas/oil | 2007 | 80 | 18,300 | 1,750 | onshore, platform |
| Ujung Pangkah | Amerada Hess | 1998 | gas/oil | end-2006 | 450 in plce | 478 | | |
| West Seno Ph1 | Unocal | 1998 | oil/gas | Aug-03 | 250 | 180 | | TLP FPSO |
| West Seno Ph2 | Unocal | 1998 | oil/gas | 2005 | 250 | 180 | | second TLP, possible delays |
| Donggi and Senoro | Pertamina, Exspan | | gas | | | 5,000 | | onshore |
| **JAPAN** | | | | | | | | |
| Sado Island (offshore) | Japan Energy/Idemitsu | | oil/gas | 2008 | | | | |
| **MALAYSIA** | | | | | | | | |
| Ansi South/South Angsi (block PM-305) | Talisman Energy | 2003 | oil | Aug-05 | 18–25 | | | platform |
| B12, off Sarawak | Sabah Shell? | 1971 | gas | 2005 | | 500 | | platform |
| E6, off Sarawak | Sabah Shell Carigali | | gas | | | | | |
| E8, off Sarawak | Shell/Petronas Carigali | | gas | 2005 | | 2,100 | | platform + compression |
| F13, off Sarawak | Shell/Petronas Carigali | | gas | 2009 | | 3,100 | | platform + compression |
| F14, off Sarawak | Shell/Petronas Carigali | | gas | | | | | platform |
| F28, off Sarawak | Shell/Petronas Carigali | 1981 | gas | | | | | platform |
| F29, off Sarawak | Shell Malaysia | 1980 | gas | post-2010 | | 100 | | platform |
| G7, off Sarawak | Shell Malaysia | | gas | post-2010 | | 100 | | |
| M3 South, off Sarawak | Shell Malaysia | 2004 | gas/cond | 2005 | | | | |
| Belud South (block 302) | Amerada Hess | 2004 | oil/gas | discovery | | | | |
| Belumut | EPMI | 1970 | oil | 2004 | 11 | 50 | | platform |
| Beryl | Petronas Carigali | 1969 | gas | post-2010 | | 400 | | platform |
| Bintang | Esso Malaysia | 1970 | gas/oil | Feb-03 | 25 | 1,000 | 250 | platform |
| Blocks PM 5,8,9,10 | Esso Malaysia | | gas | 1998 onwards | | | | Peninsular gas project |
| PM3 CAA Ph2 | Talisman | | | Sep-03 | | | | platforms |
| Bunga Orkid | Talisman | 1991 | gas/oil | 2007 | 3 | 415 | | platform |
| Bunga Kamelia blk PM 301 | Shell/Petronas | 2003 | gas | discovery | | 200 in blk 301 | | |

**Table 2: Current and planned key field developments in the Asia-Pacific region**

| Country/Field | Operator | Disc. | Oil or gas output | Start-up date | Oil res. (mn b) | Gas res. (bn cf) | Capex ($mn) | Production system |
|---|---|---|---|---|---|---|---|---|
| Bunga Zetung blk PM 301 | Shell/Petronas | 2004 | gas | discovery | | 200 in blk 301 | | |
| Bunga Anggerik-1 PM 301 | Shell/Petronas | 2004 | gas | discovery | | four payzones | | |
| Bunga Kesumba blk PM 301 | Shell/Petronas | 2005 | gas | discovery | | | | |
| Bumi South-1 blk 301 | | 2005 | gas | discovery | | | | |
| East Belumut blk 323 | Newfield Peninsular Malaysia | | oil? | eval/dev | | | | |
| West Belumut blk 323 | Newfield Peninsular Malaysia | | oil? | eval/dev | | | | |
| Lerek blk 323 | Newfield Peninsular Malaysia | | oil? | eval/dev | | | | |
| Chermingat blk 323 | Newfield Peninsular Malaysia | | oil? | eval/dev | | | | |
| Cendor (PM 304) | Petrofac (ex Amerada Hess) | | | late 2006/2007 | | | | |
| Congkak | Murphy Oil (SK 309) | 2002 | oil | | | | | |
| Guntong E (production hub) | ExxonMobil | | gas | 2006 | | | | platform, gas processing |
| Gumusut (deepwater blk J) | Shell | 2004 | oil | discovery | | | | |
| *Helang (blk SK 10) | Nippon Oil | 1990 | gas | 2003 | | 1,600 | | platform |
| *Jintan (blk SK 8) | Shell | 1992 | cond/gas | Sep-04 | 56 | 2,800 | | unmanned platform to M1 SK8 |
| Kikeh (blk K, off Sabah) | Murphy/PetronasCarigali | 2002 | oil | 2H2007 | 400 | | 1,400 | spar floating prodn platform |
| Kebabangan-3 (discovery off Sabah) | CPhillips/Petronas PSA | 2002 | oil | likely devt | | | | |
| Kenarong-1 (PM 311 offshore Pen Malaysia) | Murphy Oil | 2004 | oil/gas | discovery | | | | |
| Laila | Petronas Carigali | 1999 | gas | 2010 | | 300 | | platform |
| Serai (blk SK8) | | | gas | Jun-04 | | | | SK8 970mn cf/d to Tiga |
| *SK8 other fields | Shell | 1993/4 | gas/cond | 2004 onwards | 31 | 2,400 | | platform |
| *SK10 other fields | Nippon Oil | 1991 | gas/cond | 2012 | 4 | 100 | 37 | subsea tieback to Helang |
| West Patricia (off Sarawak) | Murphy Oil (SK 309) | | oil | May-03 | 38 | | | |
| **MALAYSIA-THAILAND JDA** | | | | | | | | |
| Cakerawala | CTOC | 1995 | gas/cond | 1H2005 | 51 | 2,850 | 800 | platform |
| A18 fields | Amerada Hess/Petronas | 1995 | gas/cond | Mar-05 | 100 | 5,200 | 1,230 | Cakerwala is Ph1 |
| B17 fields | CPOC | 1995 | gas/cond | 2011 | 57 | 1,600 | 780 | Muda plat + pipeline link |
| **KOREA (SOUTH)** | | | | | | | | |
| Donghae (East Sea) | KNOC | 2002 | gas | Apr-04 | | 250 | | 3 subsea to prodn platform |
| **MYANMAR** | | | | | | | | |
| Block A-1 | Daewoo Intnl | 2004 | gas | 2006–2007 | | 4,000–6,000 | | |
| **PAKISTAN** | | | | | | | | |
| Bhit | Eni | 1997 | oil/gas | 2003 | | 896 | 340 | onshore |
| Sawan | OMV | 1998 | gas | Nov-03 | | 1,500 | 329 | onshore |
| Zamzama | BHP Billiton | 1998 | gas/cond | 2001/2003 | 1,912 | 420 | | onshore to Sawan-Qadirpur ln |
| Rehmat block 2769-4 (Mubarak) | Petronas | | | Apr-05 | | | | onshore |
| **PHILIPPINES** | | | | | | | | |
| Malampaya (oil) | Shell | 1992 | gas/cond | 2002 | 80 | 3,100 | | subsea tieback |
| **THAILAND** | | | | | | | | |
| Arthit (B14A, B15A, B16A) | PTTEP | 1999 | gas/cond | 2Q2006 | 40 | 3,200 | | 5 wellhead plats+ prodn plat |
| Bongkot redevelop 3C | PTTEP | | gas/cond | 2003 | 6 | 500 | | plat + gas processing |
| Lanta (G4/43) | Chevron | 2004 | oil/gas | discovery | | | | |
| North Jarmjuree | Chevron | 1992 | oil/gas | 2003 | 65 | 400 | | discovery |
| Dara | Unocal | 1974 | gas/cond | 2011 | 14 | 160 | | |
| South Gomin block 13 | Unocal | 2004 | gas | 2006 | | | | |
| Phu Horm | Amerada Hess | | gas | 4Q2006 | | 20mn boe | | |
| **VIETNAM** | | | | | | | | |
| Bunga Kekwa Ph2 | See Malaysia | | | | | | | |
| Hai Thach | BP | 1995 | gas/cond | 2007 | 90 | 1800 | | platform |
| Lan Tay/Lan Do | BP/Statoil | 1993 | gas/cond | 2002 | 10 | 1,600 | 1,230 | 2 platforms |
| Rong Doi | KNOC | 1995 | gas/cond | | 12 | 800 | | platform |
| Su Tu Den (Black Lion) blk15-1 | Cuu Long Op Co | 2000 | oil | Oct 2003 | 400 | | | FPSO |
| Su Tu Vang (White Lion) blk 15-1 | Cuu Long Op Co | 2001 | oil | 2008 | 220+ | | | FPSO |
| Song Doc blk 46/02 | Truong Son Jt Op Co | 2003 | oil | discovery test 7,300 b/d | | | | |
| Thien Ung 1X | Vietsovpetro | 2055 | oil | discovery | | | | |

*Key: *to Tiga LNG project*

**Table 2: Current and planned key field developments in the Asia-Pacific region** Source: *Petroleum Review*

# Petroleum review

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# IP Week 2006

## 13–16 February 2006

Energy Institute's 92nd International Petroleum (IP) Week 2006 will be held from Monday 13 February 2006 – Thursday 16 February 2006, in London. In 2006, the theme for the week will be the changing role of the international oil company and national oil company with presentations by some of the industry's most illuminating figures who will give us their unique perspective on this.

**They include:**

- *Malcolm Wicks* MP, Energy Minister
- Jeroen van der Veer, Shell
- David O'Reilly, ChevronTexaco
- Tony Considine, TNK-BP
- John Martin, ABN Amro
- Claudio Castejon, Petrobras
- James Ball, Gas Strategies

**Key topics include:**

- The changing role of the international and national oil company
- Sustaining production in Russia and the CIS
- 19th energy price seminar – the energy mix
- LNG
- Reserves

**IP Week Dinner 2006**

Wednesday 15 February 2006, Grosvenor House Hotel, London
This year we are pleased to welcome **Lord John Browne,** CEO, BP as our guest of honour and speaker. He will be followed by John Sergeant, former BBC Political Correspondent.

**IP Week Lunch 2006 – sponsored by Platts**

Tuesday 14 February 2006, The Dorchester Hotel, London
The guest of honour and speaker at the IP Week Lunch will be the newly appointed **Mr Paolo Scaroni,** CEO, Eni

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# Emissions legislation driving EU oil quality

*Since Euro 3 emissions standards were introduced in 2000, there has been a growing requirement for engine lubricants to function over extended oil drain intervals and to provide a measure of fuel economy improvement. The result has been the development of new engine lubricant technology, write* Mike McCabe *and* Alison Fisher *of The Lubrizol Corporation.*

As the emissions standards change from Euro 3 to Euro 4 (from January 2005), there will be further reductions – between 20% and 50% depending on the vehicle type – in the levels of carbon monoxide (CO), hydrocarbons (HCs), oxides of nitrogen ($NO_x$) and particulates compared to the Euro 3 standards. The levels set are intended to force widespread introduction of new after-treatment systems, such as diesel particulate filters (DPF). The introduction of these new after-treatment systems is also creating a demand for new engine lubricant technology.

The move to Euro 4 standards is fundamentally changing engine lubricant formulations, demanding the development of new components that are optimised to deliver the required engine performance but with less impact on the efficiency of the after-treatment system.

New specifications are beginning to be introduced that restrict the level of sulphated ash, phosphorus and sulphur as a way to minimise the impact on after-treatment system efficiency. Extensive research and development is underway to create new components that provide the required engine performance as well as meet the challenge of formulating with lower sulphated ash, phosphorus and sulphur levels.

## Developing standards

In 1970, the European Economic Community (EEC) issued its first directive (70/220/EEC) detailing measures to be taken against air pollution from passenger car and light commercial vehicle gases. All EEC member states adopted this directive as of 1971, either as a replacement for, or an addition to, existing national vehicle emissions regulations. Although amended considerably since its introduction, Directive 70/220/EEC remains the basis for the current EU passenger car and light commercial vehicle emissions law.

Passenger car and heavy-duty diesel vehicle legislation has been aligned since 1992 into a series of standards known as Euro 1, 2, 3, 4 and 5. Although the compliance date for each standard differs by vehicle class, it follows the timeline shown in **Figure 1**.

The directives also include provisions for each member state to introduce tax incentives to encourage early adoption of vehicles meeting the new emissions standard. The result can be that vehicles meeting the next emissions standard enter the market at least two years before mandatory compliance.

## Passenger car market

The western European passenger car engine oil market is broken into two distinct segments:

- Initial fill
- Service fill

*Initial fill* – This market represents the engine oils placed in vehicles during the production process. This market represents approximately 7% of the demand for passenger car engine oils in Europe. The market is segmented by the performance required by each vehicle manufacturer. Over the last 10 years, the oils used for initial fill have increased in performance and now represent some of the highest performance levels in Europe. The majority of engine oils used for initial fill applications are SAE 0W-30, 5W-30 or 5W-40-based formulations.

*Service fill* – This market represents the engine oils supplied to workshops, dealerships and retail locations. This market, which represents approximately 93% of the demand for passenger car engine oils in Europe, is segmented by both performance and viscosity grade. Over the last 10 years, this market also has seen an increase in engine oil performance as a result of new vehicles requiring higher performance oils for top-up and servicing.

Whilst a broad range of viscosity grades are seen in the market, demand for lower viscosity grades (0W-30 and 5W-30) has increased, while demand for higher graders (20W-50 and 15W-40) has declined. **Figure 2** shows the change in demand for viscosity grades since 1995, with a forecast of demand changes to 2010.

The main changes in engine oil quality arise as a result of higher performance initial fill engine lubricants being required in the service fill market. As the European car park evolves over the next five years and the proportion of pre-Euro 3 vehicles declines, the demand for engine lubricants for Euro 3 and Euro 4 vehicles will increase. The result will be an upgrade in the average quality of engine oils and an increase in the demand for lower viscosity grades, as shown in **Figure 2**.

## Engine oil quality

Environmental concerns, in most cases supported by legislation, are the largest single factor impacting the performance requirements of passenger car engine lubricants.

To meet EU legislation requirements, vehicle manufacturers have developed new engine designs. This creates a demand for new lubricant performance, resulting in the development of new engine lubricant formulations. Changes in lubricant technology over the past decade are a result of three distinct factors, each of which addresses an environmental concern:

- Extended drain
- Fuel economy
- Emissions

*Extended drain* – Since 1995, the average oil drain interval for a new passenger car has increased from an average of 10,000 km to 30,000 km. This move to increase oil drain intervals primarily has been to reduce the amount of used oil requiring disposal.

To enable this extension in drain interval, the engine lubricant must provide increased resistance to thermal and oxidative degradation, lower oil consumption rates, and greater total base number (TBN) retention. To achieve these performance increases, engine lubricant formulations have evolved to use unconventional base oils (API Group III and API Group IV) rather than mineral-based oils (API Group I) and new additive technology formulated for use in conjunction with these unconventional base oils. The use of unconventional base oils also has led to a move away from higher viscosity grades (20W-50 and 15W-40) to lower viscosity grades (0W-30, 5W-30 and 5W-40).

*Fuel economy* – There are increasing demands for vehicles to use less fuel. Vehicle manufacturers are working to increase fuel efficiency in order to lower carbon dioxide ($CO_2$) emissions from vehicles, reduce the rate at which fossil fuels are being consumed, and reduce the cost of using a vehicle. In order to achieve this reduction in $CO_2$, many ACEA members have increased the fuel efficiency of their vehicles by introducing new engine designs and technology – for example, direct injection diesel engines.

These engine design changes have resulted in both an increase in the performance demanded from the engine lubricant and an increase in the requirement for the engine lubricant to deliver a measure of fuel economy. To meet these requirements there has been an increase in the use of lower viscosity grades (0W-30 and 5W-30) and an increase in the use of friction modifier technology in conjunction with new additive technology.

*Emissions* – The third factor influencing changes in engine lubricant requirements is the continuing move to reduce the potentially harmful exhaust emissions generated by vehicles.

EU legislation defines the maximum permissible emissions of a range of substances. The dramatic reduction in permissible emissions that Euro 4 introduces is resulting in vehicle manufacturers developing new engine and after-treatment systems that are, in turn, bringing new performance demands for engine lubricants.

Some vehicle manufacturers are setting significantly lower limits on the levels of sulphated ash, phosphorus and sulphur than in existing engine lubricants. Because sulphated ash, phosphorus and sulphur are some of the most fundamental building blocks of engine lubricant formulations, their reductions are resulting in the development of new additive technology and may restrict the types of base oils used to formulate engine lubricants.


Figure 1: EU emission standards timeline

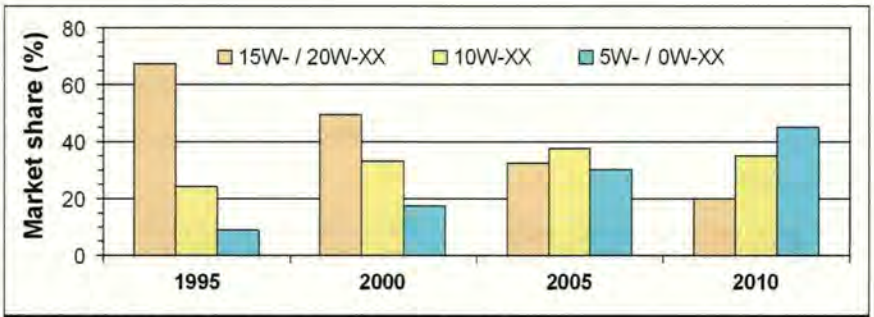


Figure 2: Change in European viscosity grade demand

## Converging trends

The convergence of these three trends is resulting in a demand for engine lubricants that can extend oil drain intervals and deliver a measure of fuel economy using lower levels of sulphated ash, phosphorus and sulphur. Oil formulators are challenged because developing engine oils to satisfy these demands requires juggling several conflicting factors:

- Emission trends are driving down the levels of sulphated ash, phosphorous and sulphur for after-treatment system compatibility.
- Fuel economy trends generally increase the levels of phosphorus- and sulphur-containing compounds to help reduce friction in the engine and increase wear protection.
- Extended drain intervals are requiring the additive system to function increasingly longer. This traditionally has been achieved by increasing the levels of many of the formulation components, leading to engine lubricants with higher levels of sulphated ash, phosphorous and sulphur.

## Engine lubricant formulation

To conclude, the trends outlined in this article have had, and are having, a number of impacts on engine lubricant formulation:

- *Impact of lower sulphated ash* – Lowering the sulphated ash of a lubricant impacts the level of metal-containing detergents that can be used. Therefore, the detergency needs to be compensated with alternative detergent and dispersant technology.
- *Impact of lower phosphorus* – The key lubricant component that contains phosphorus is zinc dialkyl dithio phosphate (ZDDP). As the levels of phosphorus are reduced to avoid poisoning effects on catalysts, ZDDP will need to reduced and replaced with alternative phosphorous-free antiwear and antioxidant technology.
- *Impact of lower sulphur* – ZDDP also contains sulphur. Whilst level of sulphur in the engine lubricants will be reduced as the level of ZDDP is reduced, the main contributor of sulphur is the lubricant base stock. API Group I base stocks can contain between 0.2%wt and 1.0%wt sulphur. Consequently, in lower sulphur lubricants, the mineral base stocks will need to be replaced by sulphur-free base stocks such as API Group III and Group IV. Some detergents also contain sulphur and will need to be kept to a minimum or replaced with sulphur-free detergent chemistries.
- *Impact of trends on engine oil formulations* – The move to after-treatment system compatible engine lubricant technology represents a significant change in additive and lubricant formulating. New lubricant specifications are being introduced that restrict the levels of sulphated ash, phosphorus and sulphur, and extensive research and investment is underway to develop and produce new chemistries. The challenge for the lubricants industry is to provide the fuel economy and extended drain benefits while formulating after-treatment-compatible engine lubricants with lower levels of sulphated ash, phosphorus and sulphur. ●

# Beating the US gas price crisis

*North America's already-tight natural gas supply/demand balance, ratcheted tighter by Hurricane Katrina, could be relieved somewhat for the coming winter by encouraging conservation and fuel flexibility, Cambridge Energy Research Associates' (CERA) Senior Director of North American Natural Gas* Michael Zenker *recently testified to the US House Government Reform Subcommittee on Energy and Resources.**

'Hurricane Katrina only added to the picture by delivering a real shock, driving prices further up and creating considerable anxiety about the adequacy of winter supply,' he said. 'Without a strong dose of good news, prices should stay at higher levels until it is clear that the winter will not deliver a demand shock, and that will not be known until most of the winter has passed.'

However, tools are available to take winter on a different path, Zenker emphasised. Strong conservation efforts have yielded dramatic cuts in consumption, including successful efforts during California's power crisis in 2001. Zenker cited CERA research that if all residential and commercial customers turned their thermostats down just 2°F this winter, the decline in natural gas consumption would more than offset the loss of supplies resulting from Katrina. Fuel flexibility can also help ease the market. Zenker says that 'restrictions on all non-gas-fired power plants should be weighed against the additional demand pressures that are shifted to the natural gas market owing to these restrictions. Judicious flexibility can be of critical importance.'

The run-up in natural gas prices has triggered strong investment by companies seeking to bring new supplies. The majority of North America's gas supply comes from mature producing areas that are in collective decline, according to Zenker, with insufficient growth expected from current strong drilling programmes. 'Land access will continue to be a key issue,' Zenker said, with 'additional gas resources known to exist in areas that are currently off-limits'.

CERA believes strong evidence exists that adding more drilling rigs by themselves will not solve the supply problem, especially with potential areas shut-off or restricted. Although drilling for gas in the US has risen by more than 175% since 2002, gas wellhead capacity has declined by over 2% during that period. CERA expects combined US (48 states) and Canadian gas supply to remain essentially unchanged between 2004 and 2010, and to decline 12% from 2010 to 2020, from lands currently available for drilling.

## LNG is key

LNG is set to become an even more important component of the country's natural gas supply. 'CERA sees no feasible way to meet long-term natural gas demand without substantial new LNG facilities,' Zenker told the House Subcommittee. CERA estimates that the combined US and Canadian market will require 10bn cf/d of LNG supply by 2010, almost half of current worldwide deliveries. This will require the LNG industry to grow at a very high rate.

While noting that new terminals will be built to withstand very large hurricanes, Zenker stated that Katrina 'underscores the need to focus on developing receiving terminals not only in the Gulf, but also in other geographic regions, closer to the consuming markets. CERA expects the development of new LNG facilities to bring enough new supply into North America to reduce prices and volatility beginning in 2008. It will be important to facilitate, and not to impede, this important, new, long-term resource.'

## Future challenges

Although the run-up in natural gas prices is fundamentally a supply problem, expected demand growth ahead, which is virtually assured, will provide further challenges. The growing use of gas in the residential, commercial and power sectors, combined with lengthy lead times – often in excess of a decade – for construction of coal and nuclear generation facilities, and restrictions on non-gas-fired power plants, add up to CERA's forecast of an 8.2% increase in US natural gas demand by 2010, with another 7.2% rise expected by 2020.

*The full text of Zenker's testimony to the House Government Reform Subcommittee on Energy and Resources is available on the CERA website at* **www.cera.com/news/details/1,2318,7605,00.html**

Date: **Tuesday 14 February**

Venue: **Dorchester Hotel**
**Park Lane, London**

Time: **12.30 for 13.00 – 14.45**

# *IP Week Lunch*

## Guest of Honour and Speaker: Paolo Scaroni, CEO, Eni

**The *IP Week Lunch* once again promises to be a key event in the petroleum industry calendar. This year we are pleased to welcome a key industry leader from Europe, *Paolo Scaroni*, CEO, Eni. Mr Scaroni became CEO of Eni in June 2005. A graduate of economics and commerce, Paolo Scaroni has held a number of executive positions in Italy and abroad.**

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j) The EI and The Dorchester Hotel reserve the right to refuse admission. Admission is strictly by ticket only.

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# Trouble on the White Nile

*In the last year's bull run for small oil company floatations on the London Alternative Investment Market (AIM), none generated as much controversy as White Nile, writes* Maria Kielmas.

Floated in February 2005 on just the promise of acquiring exploration acreage in southern Sudan, White Nile's shares spiked from 10 pence to 137 pence, before being suspended by the London Stock Exchange authorities after questions were raised about those promises. The company was to acquire a 60% share in exploration block Ba, all of which is part of an exploration area known as block 5B that was awarded to a Total-operated consortium in 1980. Total's partners are Marathon Oil and the Kuwait Foreign Petroleum Exploration Company (Kufpec). This consortium had declared *force majeure* in February 1985 following an escalation of Sudan's internal war.

The Total consortium's *force majeure* declaration was, and remains, well known in international upstream circles. It has been a major drawback for Marathon who, since the 1980s, had been hoping to farm out its stake in the block. Although there has always been much oil company interest in Sudan from a technical point of view, the *force majeure* declaration meant that no buyer wanted to take up Marathon's offer.

Matters became even worse for the US company in 1997, when the US government first imposed a trade embargo on Sudan through an Executive Order and then aid was curtailed by measures voted in by the US Congress. Such a complicated cocktail of sanctions will not be easy to remove, should Washington ever have the inclination to do so – which, at the moment, it does not. The upshot has been that Marathon has not been able to pay its share of the *force majeure* fees to the Sudanese government and is in default to its two partners who have picked up the tab.

## New model

White Nile came on the scene about three years ago as negotiations for the North-South peace agreement began. Chairman Phil Edmonds, the former England cricketer, states in stock exchange filings that he and his associates wanted to develop a financial model whereby the new Government of Southern Sudan (GOSS) would benefit from the capital markets and raise funds to develop oil in the south of the country. The idea was to create a shell company that would seek admission to the AIM. GOSS would transfer exploration rights to that company in return for a substantial stake in the vehicle.

In August 2002, prior to the signing of the peace agreement in January 2005, GOSS transferred 60% of Total's block 5B to a newly created state oil company – the Nile Petroleum Corporation (NPC). White Nile and GOSS agreed that the former would acquire 60% of NPC in return for 100% of the costs of exploration, development and production, subject to being entitled to a minimum annual internal rate of return on capital of 40%.

White Nile's spokesman Hugo de Salis rejects any notion that the Total consortium has title to the exploration acreage. He quotes GOSS Prime Minister, Riak Machar, who, he says, has made it 'perfectly clear that GOSS did not consider that Total had any rights'. White Nile's geological consultants, Henley-based Exploration Consultants Ltd (ECL), also affirm that there has been no *force majeure* declared on the acreage.

The title dispute attracted traders to the White Nile stock in the hope of shorting it. Simon Cawkwell, known in the City as 'Evil Knievel', says he doesn't see how anyone could attach value to anything that is in such legal limbo land. However, a loyal group of White Nile shareholders, notably hedge funds RAB Capital, Artemis and UBS Global, are holding on to their stock, leaving very little for free float. Consequently, when trading in White Nile resumed in June the stock fell, but still fluctuates around a median of between 80 pence and 85 pence. This situation did not alter even with the death of Sudanese Vice President and leader of the Sudanese People Liberation Movement (SPLM), the largest faction in the GOSS, in a helicopter crash in late July.

## Lots of barrels

White Nile and GOSS formally signed their deal for the block Ba acreage in April this year. The London stock market authorities permitted trading to resume once the company had filed more documentation. In these filings, White Nile quotes ECL stating that block Ba 'can be reasonably expected to have potential oil-in-place figures of up to 5bn barrels'.

In global terms, the block can be categorised as low risk/high reward, ECL says. ECL reached this conclusion through an Internet search of publicly available technical information on southern Sudan as well as some gravity and magnetic data. It did not have access to seismic that had been shot over the block by Total in the 1980s. GOSS has no access to the seismic either – only the central government in Khartoum has such access. However, despite southern Sudan's appreciable 'oiliness', the 5bn barrel figure was received by upstream experts not only as a tired old cliché, but also a questionable one given the region's overall geological character of discontinuous reservoirs in asymmetric rift basins.

## Violation

The North-South peace agreement states that a National Petroleum Commission, comprising of members from the north and the south, will negotiate and approve all oil exploration contracts. Existing contracts, it states, shall not be subject to renegotiation.

Khartoum regards the White Nile contract as a violation of this peace agreement – a view shared by Brussels think-tank International Crisis Group in a recent report on the area.

Assuming that Sudanese unity remains following the death of Vice President Garang, any future settlement will involve tricky negotiations. Total and its partners are preparing for international arbitration, while Marathon has special leave from the US State Department to pursue the case.

International lawyers think that White Nile's nuisance value could be such that it stands to gain a substantial pay-off in the form of a stake in an eventual Total-operated consortium in the old block 5B. Hugo de Salis says that such a suggestion is 'bizarre'. But stranger things have happened with small oil companies in politically tense regions.

Date: **Wednesday 15 February**

Venue: **Grosvenor House Hotel**
**Park Lane, London**

Time: **18.45 for 19.30**

# *IP Week Dinner*

**Guest of Honour and Speaker:**
***Lord Browne of Madingley, HonFEI*, Group Chief Executive, BP**

**After dinner speaker: *John Sergeant*, former BBC Political Correspondent**

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# Should Opec oil pricing move to a basket of currencies?

*With the continued weakening of the US dollar since 2001 and with Opec's 11 members heavily reliant on oil revenue as their main source of income, many members have been considering a switch in their oil-pricing policy from the US dollar to a basket of currencies as a way of safeguarding their oil revenues against a declining US currency and also stabilising oil prices.* Dr Mamdouh G Salameh* *reports.*

Iraq already prices its oil in euros, having made the switch in 2000. Indeed some conspiracy theorists detect in this act of defiance one of the real reasons for the Iraq war, on the grounds that the US feared other oil producers would follow its lead. Iran has also been considering such a switch for several years and the subject has been discussed in Saudi Arabia. Venezuela currently sells part of its oil output under a barter system to avoid using any currency at all. Last year, a senior Opec official suggested that such a move might one day make economic sense for the oil cartel. Nobody thinks any such switch is imminent, but in the aftermath of the Iraq war, some oil producers are more willing to consider a switch that would deal a massive blow to US interests.

There is, however, a political dimension for switching from the US dollar to a basket of currencies. The question is: 'Do the Arab Gulf members of Opec have the political will to make such a switch?' Any such switch will be interpreted by the US as an anti-American political act. The US could understand it if Iran and Venezuela were to adopt such a pricing policy given their anti-US attitude, but not the Arab Gulf producers whose security is defended by the US.

## Oil price background

Opec members currently supply 41% of global oil production and possess 74% of the world's proven crude oil reserves.[1] They also export some 25mn b/d of oil.

However, in recent years the economies of Opec countries and, therefore, their oil revenues, have been adversely affected by the weakening US dollar. For instance, the United Arab Emirate's (UAE) oil revenues declined from \$19.4bn in 1980 to \$6.9bn in 1985, and then rose to \$26.15bn in 2000. Without any doubt, these figures impacted heavily on the gross domestic product (GDP) of the country – GDP declined from \$30bn in 1980 to \$21.5bn in 1985, then increased to \$35.5bn in 2000.[2]

The current economic situation in the US since the terrorist attacks on 11 September 2001 and the accounting mismanagement of many American corporate firms such as Enron and WORLDCOM have shaken the US economy and the US dollar.[3] Furthermore, the introduction of the euro has provided an alternative petro- and reserve-currency. The euro is expected to play a key role in the global economy and to be a strong contender to the unstable US dollar. However, it is doubtful that the euro could, on its own, replace the US dollar as the global petro-currency.

In this article, the impact of Opec's pricing policy on its oil revenues between 1970 and 2000 is assessed. In addition, two baskets of currencies are proposed and compared against Opec's current pricing policy, which is directly linked to the US dollar. Although the price of oil showed a high degree of instability throughout the 30-year period, Opec members supplied the world's oil market with a steady supply of oil through the period in question.

In this assessment, two baskets of currencies are compared with the US dollar. The first basket consists of five equally-weighted currencies consisting of the US dollar, Japanese yen, British pound, French franc and the German deutschemark. The second basket is made up of seven equally-weighted currencies, namely, the US dollar, Japanese yen, British pound, French franc, Canadian dollar, German deutschemark and Swiss franc.

Collectively, Opec members produced and exported oil at a steady and consistent rate throughout the 30-year period. The highest level of production was achieved during the 1970s and late 1990s. Conversely, the lowest level of production occurred in the early 1980s, which reflected substantially on the price of oil going from \$1.8/b in 1970 to \$38/b in 1980 (see **Table 1**). Although there was a semi-steady rate of oil production and export throughout the 30-year period, the price of oil showed a great instability throughout the same period. These price fluctuations and instabilities had a significant impact on the economic growth of the Opec countries and their oil revenues, especially in the mid-1980s.

The assessment shows that a total saving of \$170bn to \$177.5bn could have been achieved had Opec tied its oil

| | 1970 | 1975 | 1980 | 1985 | 1990 | 1995 | 2000 |
|---|---|---|---|---|---|---|---|
| Oil exports (mn b/d) | 22.09 | 26.63 | 20.51 | 14.55 | 20.58 | 22.30 | 25.90 |
| Oil price (\$/b) | 1.80 | 11.09 | 38.00 | 27.81 | 23.17 | 17.24 | 28.50 |
| Oil revenue (\$bn) | 14.51 | 107.78 | 284.50 | 127.18 | 174.05 | 140.32 | 269.42 |

Table 1: Opec countries' oil revenues, 1970–2000 (\$bn)
*Sources:* Opec Annual Statistical Bulletins, *1988–2003;* BP Statistical Review of World Energy, *1989–2005; author's calculations*

pricing to either of the two baskets of five and seven currencies respectively in the 30-year period. These extra savings are approximately equivalent to the revenues generated in one year of an average Opec oil production and export.

Therefore, it is highly essential for the Opec countries to consider restructuring their current oil-pricing policy in order to achieve higher returns and obtain more stable oil pricing in the world's oil market. The question is: 'what basket of currencies should Opec adopt now?'

## Restructuring pricing policy

The US Energy Information Administration (EIA) estimated Opec's oil revenue in 2004 at $338.4bn, based on exports of 25mn b/d and an average price of $37/b. It projects revenues of $344.7bn in 2005, rising to $348.9bn in 2006 (see **Table 2**). The Arab Gulf producers will account for $185bn of Opec's projected revenues in 2005.

Despite this projected rise in Opec's oil revenues, economists are concerned about the health of the economies of the Arab Gulf producers for two reasons. First, the continued weakening of the US dollar against the yen and the euro, the two currencies used the most to pay for these countries's imports. Second, the gradual rise in the interest rates of the US dollar to which the Arab Gulf currencies are pegged. This could slow down economic growth in this region.

As a matter of fact, net per capita income in the Arab Gulf is three times lower in real terms than it was 30 years ago.

**Table 3** compares Opec's dollar-based oil revenues in 2004 with yen-based and euro-based revenues, and also with a basket of currencies made up of three equally-weighted yen, euro and dollar. It shows that, if Opec priced its oil in either the yen or the euro, it would have earned an extra $52bn and $54bn respectively. If, however, Opec priced its oil in a basket of currencies made up of the yen, euro and dollar, it would have earned an extra $43bn in revenue. Although Opec's revenue resulting from the adoption of a basket of the three currencies is $9bn and $11bn, short of adopting either the yen or the euro respectively, the risk spread is better. Moreover, neither the euro nor the yen can individually act as a global petro-currency while a basket made up of these two currencies and the US dollar, can.

## US implications

The US derives a small benefit from 'seigniorage' – the profit the US makes from the circulation of nearly $3tn worth of US banknotes outside the US, which cost little to print but are backed by interest-bearing Treasury bills. This is worth $10bn/y. However, the real benefit of reserve currency status is that it ensures a virtually insatiable demand for dollars from the world's central banks, who need the US currency to boost their own reserves and thereby support their own currencies.[4] China alone, for instance, holds an estimated $800bn in US Treasury bills. This has given the US carte blanche to borrow unprecedented amounts of money to fund its wars, tax cuts and consumer spending at very low interest rates.

There are far more serious implications for the US economy were Opec to adopt this shift in its oil-pricing policy and were other oil producers to follow suit. The value of the crude oil traded in the global market exceeds $1tn/y. This is equivalent to 10% of the US GDP. A shift to a basket of currencies made up of the yen, euro and dollar will add $36bn to the estimated US oil bill of $281bn in 2005. It will also expand the US budget deficit significantly, lead to lesser demand for the US currency in the global markets and would result in a further steep fall in the value of the US dollar.

It would be devastating for the dollar if the crude oil transactions were to be priced in a basket of currencies rather than in the dollar alone and the world's central banks were to start switching part of their reserves into euros and yen, or even simply stop buying dollar assets. Because oil importers would need to buy euros and yen to pay for oil, demand for these two currencies would surge. This would also increase the use of the euro and the yen as reserve currencies. The value of the dollar would collapse, since demand for dollars would fall.

Worse still, the US would find it very hard to finance its giant twin deficits – its trade and budget deficits. The dollar's reserve currency status has allowed it to run up debts no other country in history could have got away with. America's trade deficit now stands at $600bn, equivalent to 6% of GDP, while its external debts are many times bigger. This would have been unthinkable under the gold standard, when those debts would have been redeemable in gold. It was because Britain ran up similar debts in the 1930s and 1940s that sterling had to be devalued and thus ceased to be the main global reserve currency.[5]

| Country | 2004 | 2005 | 2006 |
|---|---|---|---|
| Algeria | 22.6 | 25.3 | 25.1 |
| Iran | 32.5 | 32.3 | 32.0 |
| Iraq | 20.0 | 21.3 | 24.8 |
| Kuwait | 27.4 | 28.0 | 30.0 |
| Libya | 18.1 | 19.4 | 19.6 |
| Nigeria | 29.8 | 30.6 | 32.1 |
| Qatar | 13.5 | 13.8 | 13.6 |
| Saudi Arabia | 115.1 | 113.8 | 111.0 |
| UAE | 30.3 | 31.3 | 32.4 |
| Venezuela | 29.1 | 30.3 | 29.8 |
| **Total** | **338.4** | **344.7** | **348.9** |

**Table 2: Estimated Opec's oil revenues, 2004–2006 ($bn)**
*Source: US Energy Information Administration (EIA)*

## Impact on US economy

Over the last year, portfolio (private) investment in the US has dried up amid fears that the trade deficit is unsustainable and that a fall in the value of the dollar is inevitable.

America shows no signs of being prepared to live within its means – the response to every tax and interest rate cut of the last few years has been a burst of consumer borrowing and spending. However, Asian central banks have spent billions propping up the dollar – and thus funding this debt binge – because they fear a collapse in the dollar would choke off their own economic growth. But despite this intervention, the dollar is still weakening. Moreover, the US government is now demanding Asians stop intervening, saying it damages the competitiveness of US industry.

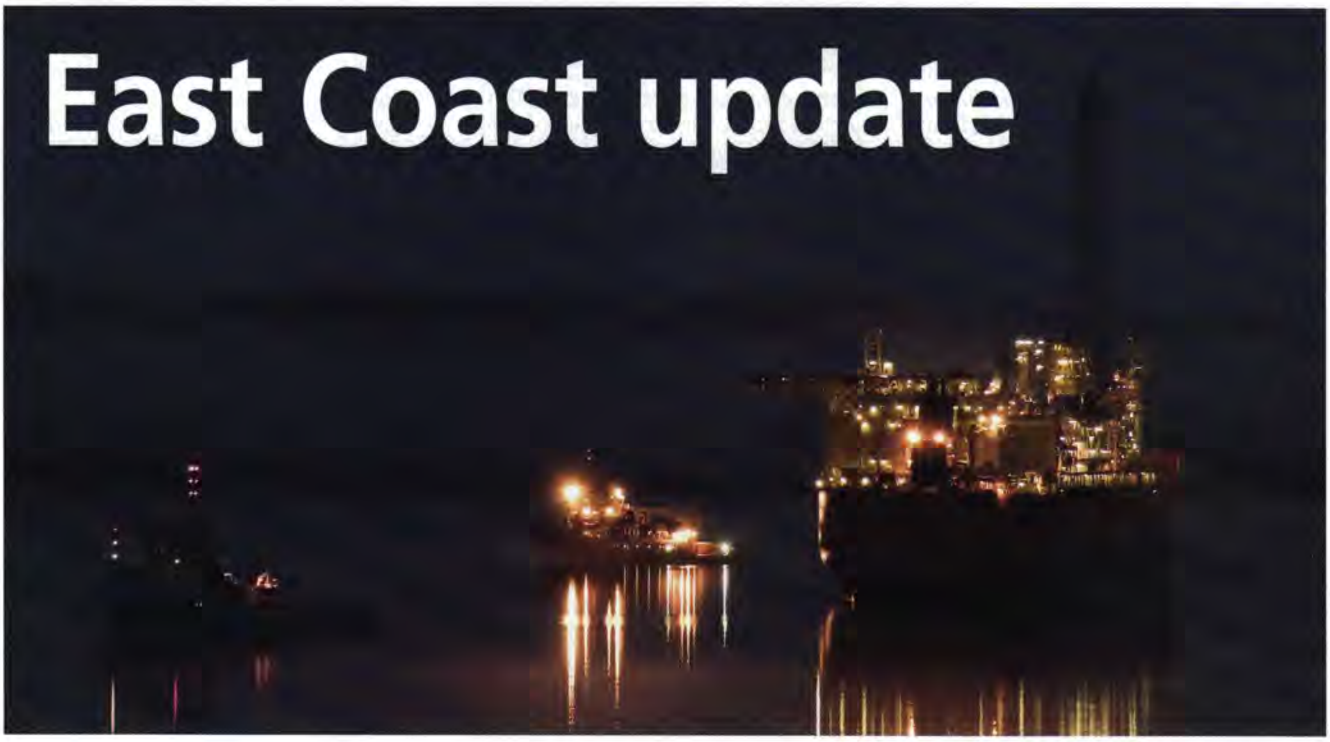
The euro and the yen are the main beneficiaries of the weaker dollar and their strength has added to their appeal as potential reserve currencies. However, a collapse in the dollar could be as much a disaster for both Europe and Japan and the world at large as for the US. The US could be faced with higher inflation, higher interest rates and a stock market and property market crash, while the eurozone and Japan could find their goods priced out of world markets. Unable to rely on exports to the US, the nascent euro

*continued on p44...*

| | US dollar | Yen | Euro | Basket of currencies |
|---|---|---|---|---|
| At 2004 $ exchange rates | 338bn | 390bn | 392bn | 381bn |

**Table 3: Opec oil revenues in 2004**
*Sources: EIA;* **Handbook of Energy & Economic Statistics in Japan; Financial Times;** *author's calculations*

# East Coast update



*The Atlantic coast of Canada is emerging as a major producer of conventional crude. But new discoveries are few and far between. Will the capricious nature of this basin lead to trouble in the future? asks* Gordon Cope.

Admire, for a moment, a scene two decades in the making – some 350 km east of St John's, Newfoundland, an immense orange ship bobs tranquilly in the North Atlantic swells. The *SeaRose* FPSO (floating production, storage and offloading vessel) is 271 metres long and can hold almost 1mn barrels of crude. Once production from the C$2.35bn White Rose field starts later this autumn, two support vessels will convey an average of 100,000 b/d to refineries in Canada and the US.

Colin Luciuk, Manager of Investor Relations for Husky Energy (the operator of White Rose and 72% owner) is justifiably proud of his company's achievement. 'White Rose has been a big success for us – it's been on time and on budget,' he notes. 'Once production at White Rose is fully onstream, we'll have around 80,000 b/d on the East Coast, which represents over 20% of our conventional production.' Ongoing drilling may also extend the life of the field for many years. 'Currently, reserves at White Rose stand at 230mn barrels of proven and probable. Delineation wells could add from 60–110mn barrels to that.'

In addition to White Rose, the east coast of Canada has two other producing offshore fields – Hibernia and Terra Nova. Hibernia, located 315 km south-east of St John's, holds approximately 865mn recoverable barrels of medium gravity oil. Since 1997, the C$5.8bn field, operated by ExxonMobil, has been producing at least 200,000 b/d from a gravity base structure, and is currently producing in the 230,000 b/d range. Petro-Canada's C$2.8bn Terra Nova field, which entered service in early 2002, is located 35 km south-east of Hibernia. The production platform is an FPSO with a storage capacity of 960,000 barrels of oil. It produces an average of 134,000 b/d of medium crude, and has an expected field life of 20 years. Altogether, the Jeanne d'Arc basin currently holds over 1.4bn barrels of recoverable crude and, by 2006, will account for over 460,000 b/d – almost equal to conventional crude production in the Western Canada Sedimentary Basin.

However, in spite of growing production, the region is going through a cyclical period in which exploration is down – and that could spell trouble in the future. 'The industry really needs eight to 12 exploration wells per year, as opposed to between two to four,' says Brian Maynard, the Canadian Association of Petroleum Producers' (CAPP) Vice President for the Atlantic Region. 'It's not at a level that creates a sustainable industry.' Is the long-term future of petroleum in the east coast of Canada in jeopardy?

## Red in the morning

In addition to a lack of sufficient exploration, several other recent trends point in a worrying direction. First, an oil spill at the Terra Nova facility in November 2004 caused a temporary shutdown that reduced Newfoundland's & Labrador's crude production by 13% for the year, underlying the vulnerability of a province that has only two (soon to be three) production sources.

The Sable gas producing region, located 200 km south-east of Halifax, Nova Scotia, is not faring much better. Despite the introduction of the South Venture field in late 2004, production continues to dwindle. Shell, which operates the Sable Offshore Energy project, reported that its one-third portion slipped from 158mn cf/d in 2002 to 135mn cf/d in 2003 and 125mn cf/d in 2004. The decision to produce EnCana's Deep Panuke field, holding 1tn cf of gas, is still on hold, pending the clarification of regulatory issues and additional reserves. And, like Newfoundland & Labrador, exploration in Nova Scotia is also at ebb tide. 'It's not dead, but activity levels are very low,' comments Maynard. 'You don't even see the number of wells as in

Newfoundland & Labrador, and that's not at a sustainable level. People are re-evaluating their interpretation of the geology; no doubt about it, Nova Scotia is a higher risk than it was five years ago.'

Regulations, both from the federal and provincial governments, are also increasing. 'The Coastal Tendering Act says you need Canadian flagged vessels for seismic and drilling if they're available,' notes Maynard. 'No other jurisdiction worldwide does this based on flags, but here, you have to go through a process, and it adds time and cost.'

On the environmental side, exploration wells also require a comprehensive study as opposed to a simple screening. 'We've done hundreds of wells, but is the environmental protection better?' asks Maynard. 'No – it's just more hoops. It adds nine to 18 months to the process when you're trying to get in the water.' This is in contrast to other jurisdictions, which are reducing regulatory burden, says Maynard. 'When you compare activity offshore Newfoundland & Labrador to activity in offshore Africa and industry responding to price signals, it's not happening in Newfoundland & Labrador.'

In addition, the Newfoundland government is airing a desire for increased fiscal remuneration. 'The regulatory burden is increasing, and now they're talking about increasing the fiscal burden,' states Maynard. 'But it's a high risk, high cost area. You can spend from C$30mn for a shallow well to in excess of C$100mn for one in deeper water – anything that reduces cost, risk and uncertainty is critical.' Efforts to rectify problems between industry and government have been addressed at a tripartite talking shop. 'The Atlantic Energy Round Table is useful in highlighting attention on issues, and some progress has been made,' comments Maynard. 'But it hasn't been enough. Levels of activity are not increasing.'


Figure 1: White Rose field, FPSO production system

## Red at night

In spite of the drawbacks, there are some bright spots. Encana has taken on a new partner, Marauder, to participate in an exploration well on trend to the Deep Panuke discovery. They hope to spud this year, pending the contracting of an appropriate rig. Marathon, which discovered the Annapolis gas field in 5,500 ft of water, has been reported to be in discussions in regards to creating a tie-back to the Sable infrastructure.

Seismic exploration, always a good sign of exploration interest, is also resurging:

- Recent geophysical data indicate that the Orphan basin, located due north of Hibernia, may contain the Upper Jurassic and Lower Cretaceous sediments that are critical for development of oil accumulations in the Jeanne d'Arc basin and the North Sea. After 15 years' absence, Shell is shooting a new 3D seismic survey in the Orphan basin and may have an exploratory well by next year.
- ConocoPhillips is planning to collect up to 6,100 km of 2D seismic in the Laurentian sub-basin located between Newfoundland and Nova Scotia (the sub-basin is on trend with Sable and may contain 8–9tn cf of gas and 700mn barrels of oil).
- Geophysical Service Incorporated (GSI) is looking at accumulating over 14,000 km of 2D data during summer and autumn 2005 offshore Labrador, which holds 4.2tn cf of discovered gas. This complements an 8,700 km shoot in 2004.

Husky Energy is also looking beyond White Rose. 'Our East Coast budget for 2005 was around C$500mn; C$450mn for White Rose delineation and C$50mn for exploration,' says Luciuk. 'We have a seismic programme in our exploration block in the Jeanne d'Arc


Sailaway of the *SeaRose* FPSO

basin.' The company also plans to drill an exploration well at Lewis Hill, located in the South Whale basin, where the company holds over 400,000 hectares. 'Hopefully, we can identify another location on the East Coast and take it from there,' comments Luciuk.

Chevron Canada Resources, which owns 27% of Hibernia and 1% of Terra Nova, also sees the region as central to the future of its company. 'We sold our mature assets in western Canada in 2004,' notes Mark MacLeod, Manager of External Stakeholders Relations. 'Our main focus areas now are oil sands, Mackenzie Delta and the East Coast. Not just Newfoundland & Labrador, but also offshore Nova Scotia and Georges Bank.' To that end, Chevron is gathering up to 8,000 sq km of 3D seismic. 'Our key focus is the Orphan basin – it's a rank wildcat area. We're putting the vast majority of our interests there. We view the area as having quite high risk but high potential,' says MacLeod.

Oil companies are also developing alternative resources for the East Coast, specifically LNG. Anadarko is building a regasification plant at Bear Head, Nova Scotia, and Spanish petroleum giant Repsol is working to build the Canaport regasification facility in St John, New Brunswick. The two approved projects, which are expected to be completed by 2008, will eventually add as much as 2bn cf/d input to the Maritimes & Northeast Pipeline that currently carries Sable Island production to the US north-east. Although some pundits believe this development might stunt exploration activity in the region, CAPP's Maynard thinks it unlikely: 'If opportunities are there, exploration companies will pursue them,' he says.

Offshore gas production in Newfoundland & Labrador may also come onstream within 10 years. 'White Rose holds around 2.3tn cf of gas,' says Luciuk. 'Right now, the gas will be fired back [un-ignited, into the reservoir] for conservation, but we are looking at ways to produce it. We could go with LNG or pipe, but right now, it looks like compressed natural gas is the way to go, probably within a decade. The *SeaRose* FPSO can handle 150mn cf/d of gas production. Once the oil tails off, we'll have a way of producing the gas.'

## In the pink

But perhaps the rosiest news is the resurrection of the Hebron project. Originally discovered in 1980, the project, located east of Hibernia, consists of three fields – Hebron, Ben Nevis and West Ben Nevis – holding an estimated 400mn to 700mn recoverable barrels of oil. Due to low prices and a steep development price (ranging from C$3.2bn to C$5.3bn, depending on the number of wells needed to exploit the heavy crude), plans were shelved in 2002. Now, with higher commodity prices expected over the next few years, Chevron, ExxonMobil, Petro-Canada and Norsk Hydro have re-entered into a joint evaluation to decide on awarding front end engineering and designing (FEED), and starting the regulatory process. The team is currently leaning towards a concrete-based platform sitting on the seabed, similar to Hibernia. If given the go-ahead, earliest production would be in 2011.

'Hebron is a huge field with significant resource size,' says MacLeod. 'But it's been the last of four to be developed because it's heavy oil. This makes for lots of challenges; you need more wells, you need to handle more water, you get less for it when sold, the topside [production facility] is more complicated – that's why were struggling with the decision.'

In addition, rising costs are putting a strain on the budget. 'The demand for steel in China and Asia has driven up the price,' comments MacLeod. 'The high cost of oil has meant that more projects are going forward; this means that contractors are in high demand, and they have the luxury of choosing projects. They are taking advantage, and the bid rates are going up. Semi-submersible rig rates have gone up by around 70%.'

While the addition of White Rose will bolster Atlantic Canada as a major conventional oil producer, and seismic exploration work is showing a resurgence, Maynard still feels that there is a long way to go. 'Currently, activity is at an order of magnitude less than what's optimal and sustainable,' he notes. 'Also, the green light for Hebron is critical – you have to maintain sufficient levels of fabrication and construction and production.'

Maynard worries that the skilled workforce that the region's nascent offshore industry has been nurturing will migrate elsewhere. 'Industry is expected to spend C$65bn on the oil sands over the next few years, and there's a shortage of labour there. If you're not working in Newfoundland & Labrador, then you can move out west.' And that means that the expense of operating offshore in Atlantic Canada could start to spiral up. 'If you lose skilled workforce in the supply and service chain, costs go up; your highest productivity is when you have one project pushing out another,' comments Maynard.

*...continued from p41*

zone and Japanese recovery would collapse.

The eurozone and Japan may hope this scenario can be avoided by collective government action, as it was in 1986 with the Louvre Accord, following a 44% collapse in the dollar's value. The answer then was interest-rate cuts, which led to a boom followed by a stock market crash in 1987. This time, a solution would most likely involve big sacrifices by the US – sacrifices that in the current political climate it may not be able to make.

## Conclusions

Opec members should seriously consider restructuring their oil-pricing policy by switching from the US dollar to a basket of currencies made up of three equally weighted dollar, yen and euro. This will safeguard their oil revenues and stabilise the oil price, while also providing a better risk spread.

However, it is inadvisable for them to price their oil in either the euro or the yen separately, as neither of these two currencies can act individually as a global petro-currency or a global reserve currency. A basket of the three biggest currencies would provide stability to the oil market and assured revenues to Opec oil producers. This will also open the door for other non-Opec producers, such as Russia and Mexico to follow suit.

The added revenues amounting to at least $43bn/y could be used to expand their oil production and refining capacities, and exploration, and also to improve their health and educational services, and renovate their infrastructure.

**Footnotes**

1. *BP Statistical Review of World Energy*, June 2005, p4 & p6.
2. *Opec Annual Statistical Bulletin*, 2000.
3. S Pearlstein, 'Corporate Scandals Taking Toll on Markets', *Washington Post*, 26 June 2002, pA01.
4. *Money Week*, 9 July 2005, p2.
5. Ibid., p2.

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Despite suffering a heart by-pass operation just 4 months previously, Sir Ranulph's pioneering spirit led him to complete a punishing schedule of seven marathons, in seven days on seven continents in 2003, again with Dr Stroud. First stop was Patagonia at the southern tip of Chile, then the Falkland Islands, Sydney, Australia, on to Singapore, before returning back to this side of the continent for a 26-mile run in London, Cairo and finally, New York. Sir Ranulph Fiennes – who has certainly lived by his family's motto 'Look for a Brave Spirit' – lives on Exmoor.

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# Gazprom-Sibneft: a transaction with many dimensions

*Gazprom recently unveiled plans to acquire Russian oil producer Sibneft, paying $13.091bn for a majority stake and a further $500mn for 3.016% of shares from Gazprombank, in what is reported to be the largest deal in the Russian oil sector to date.* Igor Tomberg, *Leading Research Fellow at the Institute of Economics of the Russian Academy of Sciences, reports, answering a number of questions posed by* Petroleum Review.

Almost three months after the first rumours that Sibneft was being put up for sale surfaced, Gazprom signed an agreement with Millhouse Capital undertaking to purchase a 72.7% stake in the oil major at $3.8 per share – which is a valuation that almost corresponds to Sibneft's market value. In addition, Gazprom has bought another 3.016% of shares from Gazprombank, thus getting a qualified majority on the Sibneft board.

The state-controlled gas monopoly will also take over other Russian oil assets that Sibneft does not own directly, but consolidates on its balance under US GAAP. These include a 49.5% share of Slavneft and its subsidiaries (TNK-BP holds a similar stake), 36.84% of the Moscow oil refinery's voting shares and 49% of Sibneft-Yugra.

'By the acquisition of Sibneft, Gazprom seeks to achieve its strategic goal of becoming a global energy company, a leader on the global energy market,' said Dmitry Medvedev, head of the President's administration. He specifically pointed to the transparent market terms of the deal, which he claims have significantly contributed to solving the problem of de-privatisation in a civilised way.

Gazprom intends to pay for Sibneft with a loan from a syndicate of banks able to finance such a transaction. It was in talks with ABN Amro and Dresdner Kleinwort Wasserstein on borrowing up to $10bn. Recently, however, Morgan Stanley and Citigroup joined the negotiations, and the sum rose to $12bn.

Gazprom is expected to pay off part of the loan (about $5bn) by the end of the year, when the government pays it the last installment of $5.7bn for its Gazprom shares. The rest will be structured in the form of long-term bonds and loans.

## Multi-dimensional deal

The deal has many aspects. Apparently, Gazprom is launching its presence on the Russian oil market. Its management has announced their intention to consolidate the gas giant's oil assets in a single division, Gazpromneft, and to boost oil production from 10.5mn t/y to between 35mn and 40mn t/y by 2010.

Many analysts believe this figure could be higher, reporting that the purchase of Sibneft will make Gazprom the fifth largest national oil producing company, with output of between 55mn and 57mn t/y (including half of annual production from Slavneft). This, however, is far from reality, if only arithmetics is applied. In 2004 Sibneft produced about 34mn tonnes of oil, Gazprom about 12mn tonnes and Slavneft 22mn tonnes. According to *Profile* magazine (on 3 October 2005), Gazprom currently controls 1.4% of all Russian oil production. (see **Table 1**). If we take into account the cumulative oil production of 460–470mn tonnes in 2004, it is obvious that the oil production of Gazprom and its subsidiaries will exceed 40mn tonnes.

Although Gazprom will own a number of oil producing assets, there has been no news of intentions to build any new refineries to process it, in addition to the refining capacity offered by the Belorussian oil refineries owned by Slavneft. (Other refineries in Russia that may change hands include those owned by Yukos, now claimed by Rosneft, and also the Mazhekiay oil refinery in Lithuania that Lukoil is planning to acquire.) Indeed, it is unlikely that Gazprom will consider refinery expansion by building or acquisition in the short-term, as it would involve considerable levels of investment. The gas monopoly's priority should be investing in the construction of LNG facilities.

## Consolidation on the cards

The subsequent break-up of Slavneft is more than likely in Gazprom's plans as the company has already indicated that it would prefer to create a powerful company – Gazpromneft – and acquire processing assets. It is not improbable that a certain pressure will be exerted on TNK-BP. For example, it has become known recently that Minpromenergo (the Ministry for Industry and Energy) and Gazprom are working on a proposal to build a pipeline to export gas to China. This pipe – as an alternative to the Koviktynn route to China – will effectively lock up the gas resources of TNK-BP in Russia and may make the whole project economically unprofitable. CEO of Gazprom, Aleksey Miller, has often stressed that the Kovikta gas should only be supplied for the needs of the country. According to *Vedomosti Daily* (on 22 September 2005), Miller has rejected the proposal from Viktor Vekselberg, co-owner of TNK-BP, on joining the shareholders of Rusia Petroleum.

Furthermore, although a recent Arbitration Court ruling cut TNK-BP's tax claims one hundred-fold, from 4bn to 40mn roubles many companies do have problems with the taxation authorities. In a dispute over Gazprom's assets, it is always possible that administrative pressure can be exerted via tax claims or other routes.

## End to controversy

The sale of Sibneft puts an end to one of the most controversial privatisations in Russia's extremely controversial privatisation history. Al Breach, Chief Economist with UBS Brunswick, told the *Financial Times* that the loans-for-shares privatisation of 1995 was 'the original sin'. In his opinion, the sale of Sibneft has closed this chapter. Gazprom paid a market value for the company, which is good news for the market, he said.

Quite explicably, all foreign analysts draw a parallel between Roman Abramovich and Mikhail Khodorkovsky, saying that the owner of Sibneft and Chelsea FC has received an incredibly lucrative deal. However, the Russian billionaire does not have to leave the country, as some American publications suggest. Abramovich is quite likely to remain Chukotka Governor. The most important aspect in this case is that the Kremlin showed its intention to resolve property issues by financial methods and not by force.

Commenting on the acquisition, Natural Resources Minister Yuri Trutnev said: 'On the one hand, this makes Gazprom the world's largest energy company, which positively influences the investment attractiveness of both the firm and also of Russia. On the other hand, the transaction arouses certain fears as to the efficiency of managing the new oil assets and the possibility of monopolising the market.'

| Company | Share |
|---|---|
| Gazprom ** | 12.4 |
| Lukoil | 18 |
| TNK-BP | 15.4 |
| Surgutneftegaz | 12.9 |
| Rosneft*** | 16 |

*Calculation according to total production in 2004
** Including Sibneft's and half of Slavneft's outcome
*** Together with Yuganskneftegaz

**Table 1: Major companies share in the production of oil and gas condensate in the Russian Federation (%)***
*Source: Ministry for Industry & Energy, Gazprom*

However, experts do not see this as a frightening situation. 'All production in producing countries is, as a rule, controlled by the state in some or other way,' the *Vremya Novostei* daily quoted Valery Nesterov of Troika Dialog brokerage as saying: 'Private investors control downstream assets. In Russia we have a transitional stage and if we are moving towards conditions in which the rest of the world lives then there is nothing to fear. Of course, private businesses are generally more efficient than state-run operations. However, it becomes a disputable issue concerning the efficient use of natural resources.'

It is obvious that the management efficiency of private companies is higher than that of the state ones. However, private oil companies are inclined to boost production by 'reaping the cream', which means developing the best fields and abandoning less lucrative wells in terrible environmental conditions. The authorities are more worried about the future of the country's resources than about efficient, but wasteful, development.

Besides, there are arguments that refute the opinion of the all-out onslaught of the state. Vadim Kleiner, Director for Corporate Research at Hermitage Capital Management and the major critic of Gazprom's management, says that: 'The nationalisation of the oil industry today reminds one of a room with two entrances: on the one hand, state-owned companies buy private assets, but on the other, there is a reversed process – Gazprom plans to remove the ring fence around its shares, and Rosneft plans to put up 49% of its shares for an IPO.'

## Strong position

Foreign analysts seem to be especially critical about the increased state presence (and influence) in the Russian fuel industry. Most probably, the reason is that it gives Russia a stronger position in the global energy market. With the current situation on global markets, this contributes to an increase of the country's geopolitical influence. Energy resources today provide a geopolitical tool as important as missiles. By the way, no one thinks of privatising nuclear arsenals – a tentative, but acceptable comparison.

Next year, Russia will chair the G8, which sees its global task as ensuring the world's energy security. Hence this close attention to the situation in the Russian oil industry. In other countries, such a transaction would be interesting only for its financial scale. However, Gazprom's purchase of Sibneft sends vibrations through all spheres, from economy to geopolitics.

# RasGas extensions rated

*Recent research* points to the changing face of LNG project financing, argues* Jan Willem Plantagie *of Standard & Poor's, citing the recently rated Ras Laffan expansion projects as examples.*

Over the past decade, as a relatively new but growing asset class, investment in LNG projects has been driven by limited-recourse 'project' financing, in which lenders can not only look to a project's performance for repayment, but also rely to some degree on the sponsors to mitigate their risk. In some transactions, completion guarantees from sponsors and off-take agreements offers additional comfort to lenders.

However, as the LNG market grows towards maturity, the typical project finance structures appear to be changing and some corporate style elements are now being included. Standard & Poor's (S&P) believes that LNG projects will increasingly look to contract with multiple customers, who will seek greater flexibility – a situation that will reflect the increasingly dynamic LNG market and the desire of individual companies to exploit opportunities in the increasingly liquid market. And while projects such as the Ras Laffan facility will continue to achieve investment grade ratings, the financial structures behind new LNG facilities could well be very different.

## Greater flexibility

Typical of transactions seeking greater flexibility are the recently rated Ras Laffan expansion projects RasGas II (trains 3, 4 and 5) and RasGas 3 (trains 6 and 7), which raised $4.6bn through commercial bank loans, bonds and shareholder loans – the latter totalling $1.38bn from ExxonMobil. Both projects guarantee each other's performance, and so are rated 'A' on a consolidated basis.

While the 'new' LNG projects will continue to rely on long-term offtake agreements, the new capacity will allow bottlenecks at existing facilities to be cleared, creating a short- to medium-term market segment. Although small in size, a reasonable sized spot market may well develop over time.

However, it is S&P's expectation that most projects will continue to rely predominantly on long-term offtake agreements. Indeed, the original 1996 Ras Laffan $1.2bn bond issue (rated 'A') came on the back of a 25-year contract with Korea Gas, while the RasGas II and 3 issues are similarly underpinned by long-term agreements. It is expected that during 2006 and 2007 only 10% of the new facilities' output will be sold on the spot market, generating revenue to cover the period between start of the contracts and expected end of construction.

The RasGas project combines existing technology in RasGas II, similar to the one used in Ras Laffan. RasGas 3 uses new technology. S&P's experience of construction in operations such as Ras Laffan and Oman LNG has been very positive, with almost flawless construction and operational performance – something that offers strong reassurance when assigning ratings. Furthermore, the facilities to be financed by RasGas II are subject to a fixed-price, date-certain construction agreement, minimising the potential for stakeholders to lose out in the event that difficulties are encountered before the project comes into operation.

Another area of interest to credit analysts is the support of the companies behind a project finance deal. In the case of RasGas II and 3, the main sponsors are Qatar Petroleum and ExxonMobil. Companies that have entered into off-take contracts include the Indian state-owned gas-buying agency Petronet, as well as Endesa, Edison and Distrigas. These companies have a key interest in successful operations as their LNG agreements with RasGas provide a key source for their respective national gas strategies. Furthermore, the scale of the expansion projects means that it has an almost global reach, resulting in a better spread of risk – and avoiding exposure to a particular region's market.

Most projects offer lenders significant collateral packages as security. The collateral in the RasGas transactions mirrors more that of an unsecured corporate financing. While this may concern some lenders, the ability to seize and control assets will, however, often already be limited due to legal systems in the host countries or the strategic nature of the assets to a country that will not allow outside control over these assets. The RasGas transactions have proven that even despite the absence of such a traditional project finance security package, strong ratings can be achieved. A key issue will, however, be the location of a project, the involvement and importance of the project to the sponsors and the credit quality of the host country.

## Sponsor involvement vital

Producing LNG at the Ras Laffan facility is particularly important to the project's primary sponsors. Qatar Petroleum (rated A+) is the key contributor to Qatar's economy, with oil and gas revenues representing 64% of total general government revenues for the past fiscal year. And 'AAA' rated ExxonMobil – while a leading player across the energy industry – stems its profitability from its exploration and production activities. A key factor in the company's strength is the scale of its proven reserves – some 22bn boe – with Qatar accounting for 1.7bn boe of the company's 1.8bn boe reserve additions in 2004.

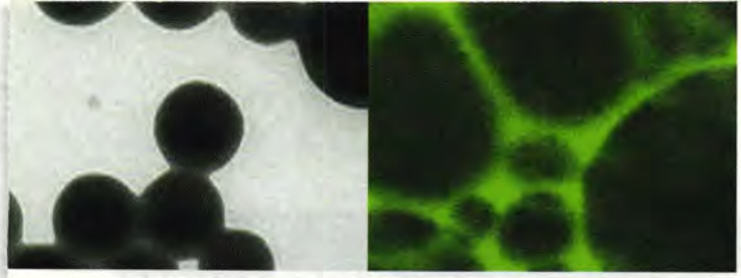
But, while the commitment of the sponsors is a strength, S&P's credit analysts also note that many of the companies who have entered into off-take contracts have ratings below the 'A–' preliminary rating assigned to RasGas II and 3. Indeed, initial sales will see about 74% of LNG sales (by volume) go to offtakers with 'BBB' or lower ratings (or to spot sales), although this will decline to about 22% by 2011, assuming affiliates of ExxonMobil start buying the increased output once trains 6 and 7 come online.

In addition, while negotiations are in progress for these new trains, the absence of signed construction contracts introduces costs and schedule risk to this part of the project's expansion. The lack of sale/purchase agreements for trains 6 and 7 introduces marketing risk, although a heads-of-agreement contract with ExxonMobil is in place.

Furthermore, while the strength of the RasGas II and 3 rating stems from the strong support offered by the project's long-term offtake agreements and sponsors, the increasing globalisation of the LNG industry means that LNG projects will increasingly look to contract with multiple customers, who will seek greater flexibility – a situation that will reflect the increasingly dynamic LNG market and the desire of individual companies to exploit opportunities in the increasingly liquid market.

Although projects like Ras Laffan and RasGas will continue to achieve investment grade ratings, the strength behind new LNG facilities in more exotic locations could well be very different.

**For further information, see the report* LNG Project Finance: Clearing The Investment Grade Hurdle, *available at* **www.ratingsdirect.com** *Jan Willem Plantagie can be contacted at e:* **jan_plantagie@sandp.com**



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Eivald Røren, President, WPC (far left), with Louise Kingham, Energy Institute CEO (second left); Mr Tripathi, Secretary Petroleum (third left); and guests at the launch of the EI's Indian Branch

*Held for the first time on the African continent, the theme of this year's 18th World Petroleum Congress (WPC) was 'Shaping the energy future: Partners in sustainable development'. This theme was certainly debated and discussed at length throughout the week, particularly in some of the key plenary sessions.* Lawrence Slade, *the Energy Institute's Business Development and Technical Director, reports.*

# Partnerships and an African dawn

With over 500 speakers at this year's event covering a diverse range of topics including refinery optimatisation, operational transparency and the hydrogen economy, delegates were spoilt for choice. The event attracted over 3,500 delegates from around the world, and over 200 exhibitors. As a result, the 18th annual WPC represented an excellent opportunity to network with industry peers – as one visitor put it: 'Attending WPC allows you to carry out six months' worth of client visits in one week.'

Partnershipping was one of the major issues addressed during WPC – just how do you deliver partnerships and what goes into a successful one, particularly in the developing countries of the world, where their indigenous natural resources are often the only source of national wealth? The challenge as laid out for the oil and gas industry is how best to responsibly develop such resources, while, at the same time, developing a sustainable infrastructure that will last long after the oil companies have gone.

The discussions surrounding partnerships in particular focused on developing the small- and medium-sized enterprises (SME) sector in developing nations. Such organisations often account for more GDP (gross domestic product) than any other sector in developed countries. Christophe de Margerie, Executive VP Exploration and Production at Total, put very forcefully Total's obligation to the countries within Africa that it operates in. He explained that partnerships were key not just with national oil companies NOCs but that they also had to include individuals from the local community and, critically, had to develop a sustainable SME sector that could help drive that country's or region's economic growth. De Margerie also stressed that politics was not a game for oil companies to be involved in, rather they should work in partnership with the appropriate government authorities to build successful operating conditions.

## Transparency and corruption

Allied to the partnership debate, a lot of time was given to looking at transparency of operations, in particular, the issue of corruption – a thorny subject that appears to loom as large as ever. The point made by several speakers was that accepting corruption as a normal part of doing business in the developing world only served to feed its appetite, leading to further cost and depriving local communities of vital income derived not just from the exploitation of local natural resources but also of the support infrastructure that is intrinsic to any development.

In a forthright speech to Congress, Paul Boateng, the ex-Secretary to the UK Exchequer and currently British High Commissioner to South Africa, attacked Opec for its lack of transparency. In particular, he highlighted the lack of openness in its decision-making process and the need for the cartel to publish reserves figures for its members.

Of course, outlawing corruption is only one part of the transparency issue. Reserves are still a cause for concern on world markets. Earlier, Saudi Arabia's Oil Minister, Ali Al-Niami, had put to Congress that there was no shortage of resources to be developed to meet projected demand levels. He argued that the problem lay not so much in availability but in deliverability, with the industry's infrastructure stretched too thin. He stated that by 2009 Saudi will have raised its production capacity to 12.5mn b/d, maintaining spare capacity of up to 2mn b/d, with the potential for 15mm b/d if demand is high enough. (For more details, see *Petroleum Review*, October 2005). He also pointed to Saudi's plans to increase its domestic refining capacity.

In the same session, Rex Tillerson, President of ExxonMobil, referred to the US Geological Survey USGS report that estimated a further 2tn barrels of conventional oil is yet to be recovered, plus unconventional reserves. This was also picked up on later in the week by Jeroen van der Veer of Shell.

## Renewables and the environment

While on the one hand Congress was being assured that there were sufficient reserves to meet the IEA's (International Energy Agency) projected demand call on hydrocarbons out to 2050, Christopher Flavin, President of the Worldwatch Institute, presented an alternative view. Flavin – while not disagreeing with his co-speakers from the oil industry – presented the view that while renewables currently accounted for only 3% of world energy capacity, environmental pressures and rising costs could see the renewable sector enter an age of exponential growth, with new technologies coming onstream, constantly improving both the performance and economic viability of the sector – replicating the growth of the oil industry in its early days. In an interesting conclusion, he posed the question as to whether you would rather join a sector of the energy industry about to enjoy exponential growth or its established, slow growing competitor?

Environmental concerns were never far away from the fore during the week. Both BP and EnCana led discussions on carbon capture and storage. EnCana cited its Weyburn field in south-eastern Saskatchewan as a proven example, with production levels having increased by 35% since carbon dioxide ($CO_2$) injection commenced. Some 95mn cubic ft of $CO_2$ is injected daily, piped over 160 km from the US. BP presented its plans for the North Sea Miller field $CO_2$ injection and power generation project.

Standards and best practice operations were also a recurring theme during WPC. Conversations with delegates and during the two standards workshops that were held, illustrated that there is both a great appetite and need for standards and best practice guidelines throughout the industry, particularly from the developing nations. Improving HSE (health, safety and the environment) performance certainly appeared to be an area that the indigenous NOCs are moving very quickly to meet.

## New EI branch

Following the spirit of partnership, the Energy Institute (EI) signed a major agreement with the Indian School of Petroleum (ISP) during WPC.

With over 600,000 people currently employed in the Indian energy industry and a growing need for energy to support its rapidly growing economy, there is an obvious need for a well-educated and professionally recognised workforce in the country. ISP works closely with UPES to provide the future supply of home-grown talent for the Indian energy industry.

During the signing ceremony, Sanjay Kaul, Director of ISP, commented: 'In today's world, partnering has proven itself one of the most powerful tools for dealing with fast changing markets, and alliances have become an integral part of contemporary strategic thinking. The partnership between ISP and the EI will not only provide global access to EI services, but will also ensure that regional and local factors peculiar to the Indian context are catered for through the collaboration between two well established knowledge-based organisations.'

'Energy professionals in India will benefit immensely through this alliance, as international best practices and technology updates of the energy sector will now be available for sharing, in order to help them cope with burgeoning industry growth rates and increasing international prices.'

Louise Kingham, EI Chief Executive, said: 'We are very pleased to announce this new branch in India. With 13 branches in the UK, and five other international branches in Eire, Hong Kong, Houston, the Netherlands and Switzerland, we are proud to extend the benefits of membership to energy professionals in India. Support of ISP and its activities will be central to the branch in promoting new talent and encouraging graduates to join the energy industry.'

The EI and ISP were delighted that Mr S C Tripathi, IAS, Secretary to the Government of India, Ministry of Petroleum and Natural Gas, and Dr Eivøld M Q Roren, President of the World Petroleum Congress, were able to attend the ceremony. After the agreement had been signed, Mr Tripathi was presented with an Honorary Fellowship of the EI. Accepting the award, he commented: 'I am honoured to receive this Fellowship and I look forward with interest to seeing how this worthy partnership develops.'

(For a report on India's energy sector, please see p19).

## Dewhurst lecture

This year's WPC ended with the Dewhurst Lecture, delivered by Lord Browne of BP, who took the opportunity to review the achievements of the industry over the last 35 years. He put this into perspective by then looking at how the industry is currently positioned to handle the challenges presented by rapid economic growth, environmental issues, significant growth of world trade and investment.

With many naysayers forecasting the end of oil, Lord Browne believes that the industry is not facing a shortage – he pointed towards the many decades of booked reserves and again to the reserves of heavy and or unconventionals in Venezuela and Canada that have yet to be exploited.

He went on to highlight the massive levels of investment needed to be made by the industry in order to bring new supplies to market, suggesting that some \$200bn/y was needed in oilfield development alone, out of the IEA's estimate of \$560bn/y required for the energy industry as a whole.

Lord Browne went on to refer to the low investment levels of the 1990s, which have now been left behind – helped in no small part by the underpinning of prices since the turn of the century. Around \$50bn/y has been invested in the upstream sector by the top five oil companies, with BP having invested \$50bn in this sector since 2000.

It is now broadly acknowledged that the current pricing issues are as much related to processing throughput as to supply inadequacies. Lord Browne referred to this during his lecture and – interestingly, given the workshops and roundtables earlier in the week on standards – pointed to the problems caused by differing specifications between regions of the world and, therefore, the pressures this puts on an already tight market during crises such as Hurricane Katrina. In this example, Lord Browne reflected on how, by relaxing minor product specification regulations, individual states were able to ease supply difficulties and restore order to the market in the wake of Katrina.

Picking up on the sustainability issue, and echoing comments made earlier in the week, Lord Browne went on to discuss how the industry is only now understanding how important it is to be engaged with the countries within which you operate – not just paying taxes, but also playing a part in the successful development of their economies, being transparent and avoiding corruption, staying out of politics and political payments, and helping to make sure a country is ready to make full use of the wealth that resource development can bring.

Lord Browne also highlighted the need for partnerships – with NOCs and host governments – the industry's challenge being to make such partnerships work and to build them based on mutual advantage.

He reflected on the role of governments – on the one hand stating their importance in making sure investment incentives for industry are in place for example, but on the other hand stating that governments alone won't deliver energy security. That's down to the oil industry, he said.

Lord Browne concluded by posing Congress with some questions – In what water depth will the industry be operating in by 2020? What will the average recovery rate be by 2020? When will we see the first emissions-free car? How will the alternative fuels market develop?

Lord Browne left the Congress in no doubt that the industry is well placed to deliver the investment, change and technological advances needed to meet the challenges of the next 30 years.

## A final word

In all, the 18th WPC delivered its objectives, with many thought-provoking papers looking at issues on a macro basis and addressing how the oil industry deals with concerns such as transparency, reputation and corruption. There were also numerous excellent technical papers.

*The 19th WPC will be held in Madrid, from 29 June to 3 July 2008.*

The *18th WPC Congress Proceedings* will published by the Energy Institute at the end of the year. The proceedings will be available in a fully searchable electronic format on DVD and include the papers and presentations of plenary and keynote speeches, review and forecast papers, technical papers and posters, country presentations, special sessions and round tables.

The full price will be £650. *A special pre-publication price of £550 is being offered for a limited period.* Please contact Portland Customer Services and quote WPC18PPP *before 21 November 2005* to order a copy at this special pre-publication price.

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# Improving safety

Kerry Hoad, *EI Technical Officer, looks at how the oil and gas industry can improve the safety of its operations by applying human factors methodologies.*

With human factors being seen as a crucial way to further improve the safety performance of the industry's operations, the Energy Institute formed a Human Factors Working Group. It is comprised of members from BP, ConocoPhillips, Shell International E&P, ExxonMobil, Kingsley Management Services and the Health and Safety Executive (HSE) – representing both upstream and downstream operations.

> *'The Safety Information Bulletins provide the energy and allied industries with a vehicle that all can use to share examples of human factors best practice and of lessons learned following incident investigation. Through our willingness to share knowledge with one another we demonstrate our commitment to the delivery of the very highest standards of safety performance in our operations. We learn from each other and in doing so help each others' HSE management systems to improve and flourish.'*
> Graham Reeves, Chairman, EI Human Factors Working Group

The Working Group has a programme of work focused on developing resources that will be of use to the industry. Earlier articles in *Petroleum Review* (March 2003 and March 2005) have referred to the *Human Factors Briefing Notes* and the *Staffing Arrangements User Guide* developed by the Group. This article refers to the new *Safety Information Bulletins* and the *Top Ten Human Factors Issues* listing, in addition to reviewing the Working Group's current activities.

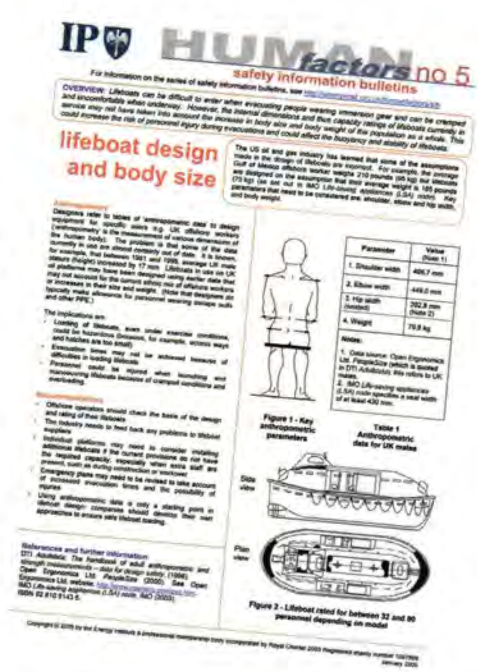
## Safety information bulletins

To raise awareness of the possibilities offered by human factors the EI Human Factors Working Group, with the support of EI technical partners, commissioned an external consultant to establish a series of *Safety Information Bulletins* based on:

- Lessons learned from incidents or near misses.
- New methods of working.
- Novel human factors techniques.

The *Bulletins* have been designed to encourage information sharing on the successful application of human factors methodologies to petroleum and allied industries operations.

Each *Bulletin* begins by providing an overview to the human factors aspect, it then describes the issue in detail with the use of various illustrative media, including flowcharts, illustrations and graphs. The *Bulletins* also provide references significant to the pertinent *Human Factors Briefing Note* or other suitable reference. They cover a spectrum of issues, ranging from occupational safety through to those with major hazard potential – some of which are relevant to both offshore and onshore operations, whereas others apply to individual sectors. (See **Figure 1**.)




The *Safety Information Bulletins* are available free of charge through the Human Factors section on the Energy Institute website at **www.energyinst.org.uk/humanfactors/sib**

The Working Group is looking to further develop the *Safety Information Bulletins*. If you have information on the successful application of human factors methodologies to share with other professionals in the petroleum and allied industries, the Group will review your draft with a view to adding it to the series of *Safety Information Bulletins*. Two more bulletins are expected to be added to the service in early 2006.

| Human factors aspect | Organisational agreements | Major hazard potential | Task related occupational safety | Design (including ergonomics) |
|---|---|---|---|---|
| **Safety Information Bulletin** | | | | |
| 1. Manual and mechanical handling | | | √ | |
| 2. Safety when using ladders | | | √ | √ |
| 3. Assessing staffing requirements for hazardous situations | √ | √ | | |
| 4. Improving alarm systems | | √ | | √ |
| 5. Lifeboat design and body size | | | | √ |
| 6. Managing organisational change | √ | √ | | |
| 7. Integrating human factors into design and modification of plant | | √ | | √ |

Figure 1: Coverage of EI *Safety Information Bulletins*

## Top ten listing

The EI Human Factors Working Group has recently updated the *Top Ten Human Factors Issues Facing Major Hazards Sites – Definition, Consequences, and Resources* – which can be downloaded, free, from **www.energyinst.org.uk/humanfactors/topten**

A set of linked pages for each issue lists resources in support of the HSE's top ten human factors issues facing onshore major hazard sites in the chemical and allied industries – issues that are similar to those faced in the offshore major hazard sector.

Each issue is defined and illustrated, explaining the consequences of failing to manage it adequately. Sometimes this is illustrated by referring to key case studies. In addition, each issue provides three levels of resources:

- **Introductory resources** – Incident reports, briefing notes or sections of longer resources that should assist the user in gaining some understanding of the issue.
- **Practical tools** – Resources enabling the user to assess whether the issue is being adequately addressed and to identify what improvements are required. Typically these contain checklists.
- **Advanced resources** – Either detailed research reports, possibly focusing on a single aspect of the issue, or reference texts.

At the end of the document some relevant web links are provided for access to additional information.

Users of the top ten listing are encouraged to provide feedback on the applicability of the resources listed (for example, successes in using them or limitations to their applicability) and to identify additional resources to supplement the listings.

## Continuing activities

As part of the Working Group's ongoing projects, work has been commissioned to produce a publication on the *Development of guidance on improving alertness through effective fatigue management in the petroleum and allied industries*, as well as a project to research into the viability of using sleep contracts as a control measure in fatigue management.

The guidance aims to improve thinking on the link between fatigue and major incidents. It will include case studies and cover areas such as standby hours, descriptions of long-term effects of fatigue and sleep contracts.

More information will be made available from the fatigue page on the EI website. **www.energyinst.org.uk/humanfactors/fatigue**

# Russia to export its oil south

*Predictably, BP Azerbaijan has said that it does not want to export oil produced in the Azeri sector of Caspian Sea via the Baku-Novorossiisk pipeline. This means that Russia, which is already losing its influence on the Caucasus, will suffer serious economic losses, writes* Anatoly Belyayev, *Director of Analysis at the Centre for Current Politics.*

Baku explains its decision in terms of economic expediency. BP Azerbaijan pays between \$4 and \$5/b if it exports Caspian oil by rail via Georgia, whereas the Baku-Novorossiisk route costs three times more.

However, economics is not the only thing that matters. The Baku-Tbilisi-Ceyhan (BTC) pipeline, the main rival of the Russian route, will start operating this autumn. This allegedly unprofitable and controversial project was launched in 1998 in Ankara, when the Presidents of Turkey, Uzbekistan, Azerbaijan, Kazakhstan and Georgia, plus the then US Energy Secretary William Richardson, signed a declaration committing themselves to facilitate the construction of the pipeline. Unfortunately, the consortium's Western members were in no hurry to finance the project.

## Political pressure

The 11 September 2001 terrorist attacks in the US and rocketing global oil prices increased US and EU demand for oil source alternatives to the Middle East. The US, Israel and Turkey, all greatly interested in this route, pressured hesitant reluctant businessmen. Political pressure coupled with rising fuel and energy prices made the project more attractive – and much more profitable. It is hardly surprising that BP Azerbaijan President David Woodward called the Caspian region 'a new promising energy source independent of the Middle East and Russia'.

The Kremlin naturally wanted to pump Caspian oil via Russian territory. Russia's Lukoil even sold its 10% stake in the Azeri-Chirag-Gunashli deposit, which gave it priority rights to implement the BTC project. Moreover, Lukoil wanted to sell its stake in the Shakh Deniz gas-condensate deposit and to leave the Caspian region. Besides, the Caspian Sea's uncertain legal status played into Russia's hands, questioning the legality of oil production in the Azeri sector that was being disputed by Iran and Turkmenistan.

However, the more powerful global players – the US and the EU – won this game, taking advantage of Kazakhstan's desire to create alternative oil-export routes. The new pipeline would then be filled to capacity. President Nursultan Nazarbayev of Kazakhstan, who spoke at the pipeline opening ceremony, suggested that the Caspian port of Aktau in Kazakhstan be included in the pipeline's name, thereby hinting that Astana wanted to export its oil via the new pipeline.

Kazakhstan will no longer have to pump its oil to Europe along the Russian route alone. In this way Russia lost a serious lever of pressure on its ally.

Russia's regional influence will be impaired, because the West now considers Azerbaijan as the main Caspian-oil supplier along this strategic route. Georgia's importance as the transit territory will also grow. Moreover, permanent US military bases may soon appear to guard Caspian deposits and the pipeline itself against possible terrorist attacks.

## New political-energy situation

Russia is facing another negative consequence of a new political-energy situation. As is known, the new Ukrainian leadership is trying to reduce its energy dependence on Russia and to enhance its own role as a transit territory for oil exports to Europe.

Thus the southern hydrocarbon-export route will serve as a full-fledged alternative to Russian pipelines and deprive Russia of money and additional leverage to influence its European partners and CIS neighbours.

As for the Baku-Novorossiisk pipeline, it is likely to be reversed within a year to boost the export potential of the new BTC pipeline. Indeed, just recently, representatives of BP, one of the two major players in Russia's TNK-BP, said that they plan to export all Russian-produced oil along the new BTC pipeline, using the Novorossiisk-Baku pipeline for the purpose.

# Egypt's steady stream

Karl Nietvelt, *of ratings agency Standard & Poor's, explains how the Egyptian General Petroleum Corporation (EGPC) has taken advantage of its reliable delivery of naphtha products and crude oil.*

An Egyptian oil export sale securitisation has been assigned an underlying rating of 'BBB' by Standard & Poor's. The deal – which essentially sees debt issued on the future sale of crude oil and naphtha – was originated by Egyptian General Petroleum Corporation (EGPC), and is a first for Egypt.

Three tranches of bonds have been issued through securitisation vehicle Petroleum Export Ltd. The first two tranches – \$500mn (six-year term) and \$250mn (five-year term) respectively – are insured by MBIA Insurance and XL Capital Assurance, and carry 'AAA' insured ratings, while the third tranche – worth \$800mn (six-year term) – is not wrapped and stands on its 'BBB' standalone rating.

The benefit of securitising future revenues lies in the ability to accelerate investment on the back of a stable existing dollar-denominated income stream. Under the terms of the forward sale agreement, EGPC is required to deliver a set amount of each of the products to Petroleum Export each month. These deliveries are assigned in priority over EGPC's sales to other clients.

## Quality counter-party is key

Apart from identifying strong performance risk, a quality counter-party is the key to a successful securitisation. The EGPC transaction has a major advantage in this regard, as it has secured an offtake and price hedge agreement with Morgan Stanley Capital (MSC; rated 'A+' and guaranteed by Morgan Stanley), which will see MSC obligated to purchase the products once they are loaded on to tankers at market value terms. Importantly, MSC will also provide a price hedge, which ensures that pre-agreed minimum Brent and Naphtha floor prices are achieved over the six-year duration of the transaction, should the market prices fall drastically.

The transaction further benefits from a debt service reserve account, which has been established to ensure minor financial bumps are smoothed out. Further flexibility is gained as EGPC is allowed an operational shipment tolerance of 10% of products shipped each month. In the event of a shortfall, the company can choose either to make up the deficit in the following month, or to make a 'true-up' payment in cash to Petroleum Export. Dropping below the 10% margin would see financial penalties incurred, and a failure to deliver within the 10% margin is considered a default.

## Weighing up the risks

In line with the underlying rating of 'BBB', there are some risks that Standard & Poor's is particularly mindful of. Chief among these is the risk that EGPC will be unable to meet its delivery obligations. However, Standard & Poor's has looked at EGPC's historical performance and reliability as an exporter, and believes that the company's ability to meet its obligations (including during times of financial stress) are consistent with the deal's rating.

The second area of risk concerns the potential for interference by the Egyptian government. EGPC is important to the Egyptian economy, both domestically and as a foreign exchange generator, and it is possible that the government could attempt to interfere with the Petroleum Export deal if severe financial stress involving either EGPC or the Egyptian government occurs. The cost in reputation to EGPC and the Egyptian government would, however, be sufficiently damaging that any intervention would be exceptionally hard to justify. Moreover, the forward sale agreement is subject to arbitration clauses, which acts as a final deterrent, as *liens* could be awarded that could extend to any and all of EGPC's assets outside the public domain. These should include EGPC's shipments of crude and related products, its share of joint ventures, liquefied natural gas (LNG) projects, and any foreign bank accounts.

## Extracting the positives

There are, however, a number of facto rs that strengthen the deal's rating. At the top of the list is the strategic importance of both the deal and EGPC to the Egyptian government. Just as sovereign interference is a cause for concern, under Egyptian law EGPC cannot become insolvent or be filed into bankruptcy without prior change to the law that originally established EGPC. EGPC's historical and anticipated performance is one of the leading drivers for the Petroleum Export issue's rating, which at 'BBB' is two notches above the 'BB+' rating of the Arab Republic of Egypt – a rare feat.

Another important consideration in assessing EGPC's performance ability and intervention risk is the type of oil product to be exported under the transaction. The poor heavy, sour quality characteristics of Ras Gharib production mean that it cannot be refined in Egypt. Similarly, the production of naphtha – for which Egypt is one of the world's top 10 producers – far exceeds domestic demand. Clearly, there are substantial incentives to ensure oil is delivered.

In any securitisation, modelling cashflow is a vital part of mapping a transaction's performance. With Petroleum Export, Standard & Poor's performed a series of cash flow analyses using the scheduled volume of crude and naphtha shipments and various pricing stresses to reflect potential future market conditions. Although both crude and naphtha exports are expected to trend upwards slightly in the coming years, Standard & Poor's imposed additional stress reductions in the shipment volume of both products in addition to pricing stress reductions.

Among the various stress scenarios analysed, one stressed a drastic decline in all production and low crude prices over a six-year period. The analysis proved that it can withstand a 50% decline in 2005 Ras Gharib production levels (assuming no new field production) at a Brent price of \$20/b.

Overall, however, the ability to draw on future income through an investment grade notes issue will offer EGPC a useful tool in maintaining its competitive edge and ability to respond to the dynamic oil market. Looking forward, Petroleum Export may well be the first of many similar deals in gas and oil rich countries across Africa, the Middle East and the CIS.

ProEn's new biogas plant powered by three of GE Energy's Jenbacher CHP engine systems was commissioned 1 July 2005, near Soltau, Germany

# Balancing the energy portfolio

*While renewable energy options such as wind and solar power have been gaining global momentum, no single solution will be able to meet all of the world's growing requirements for electrical power. Gas-to-power technologies, including gas turbines and gas-fired reciprocating engines, continue to play a major role in the global energy picture and form the cornerstone of a balanced energy portfolio, writes* David Slump, *General Manager, Global Marketing, GE Energy.*

Improvements such as higher fuel efficiency and advanced emissions control technology are leading to improved gas turbine output relative to emissions. Forty years ago, simple-cycle gas turbines operated at thermal efficiencies of between 28% and 29% – today's natural gas-fired, combined-cycle systems are capable of reaching 60%. This allows tremendous increases in power output at a lower rate of fuel consumption.

The first combined-cycle system designed to achieve 60% thermal efficiency – a new industry milestone – is the H System™, GE's most advanced gas turbine combined-cycle technology to date. The H System uses a closed-loop steam cooling system and advanced coating materials to achieve the higher firing temperatures required for its increased efficiency. For every unit of electricity produced, it uses less fuel and produces fewer greenhouse gases and other emissions, when compared to other large combined-cycle systems. The first system was installed and began site testing at the Baglan Bay power station in South Wales in late 2002, entering commercial service in September of 2003. It has since then completed more than 10,000 hours of successful operation.

Building on experience gained from the Baglan Bay operation, GE recently

GE Energy has upgraded its 50-hertz H System from 480 to 520 MW
Shown here is a side view of a GE Frame 9H gas turbine rotor

announced a technology upgrade. Originally designed to produce 480 MW, the 50-hertz, 109H combined-cycle system now is capable of 520 MW. The uprated system further improves the economies of scale provided by large gas turbine combined-cycle plants by enabling plants with fewer gas turbines to generate larger blocks of power.

GE also continues to evolve its F technology – the latest gas turbines are capable of combined-cycle efficiencies in the 57% to 58% range. The company recently achieved a milestone with its 9FB gas turbine, one of the world's most advanced air-cooled 50-hertz gas turbines. The first project in the world to feature this technology, Group III of the Arcos de la Frontera combined-cycle plant in Spain, has entered its testing phase, with the first firing for one of the two gas turbines that comprise the GE 209FB combined-cycle system at the plant held recently. Using natural gas, the 209FB system is rated at 58% efficiency. Addressing the growing need for cleaner power, the gas turbines at the Arcos plant are equipped with GE's advanced, Dry Low NOx2+ combustion system which will limit $NO_x$ (nitrous oxides) emissions to 25 ppm.

## Aeroderivatives

Increased efficiency isn't limited to the large-frame gas turbines. In the aeroderivative arena, GE Energy has introduced the LMS100™, claimed to be the world's most efficient simple-cycle gas turbine. This technology represents the first time that GE has combined components from its heavy-duty and aeroderivative gas turbines to provide significant improvements in gas turbine efficiency. The LMS100 successfully completed initial testing of its core engine in December 2004. The first gas turbine package has been assembled and is undergoing full-scale validation testing through December 2005. The unit has achieved full power (>100 MW).

The first order for an LMS100 was placed by Basin Electric Power Cooperative of Bismarck, in the US, for installation at a site in South Dakota. In mid-2005, GE signed a contract to pro-

The Arklow Bank offshore wind park in the Irish Sea – a demonstration site for GE Energy's offshore wind power technology – was inaugurated in May 2005

# Ecomagination

Wind and solar technologies have a major role in 'ecomagination' – GE's company-wide initiative to help customers meet today's pressing environmental requirements. Launched in May of this year, ecomagination is 'GE's commitment to address challenges such as the need for cleaner, more efficient sources of energy, reduced emissions and abundant sources of clean water,' said Jeff Immelt, Chairman and CEO of the General Electric Company.

As part of the initiative, by 2010 GE will be investing $1.5bn/y in research for cleaner technologies, up from $700mn in 2004.

## Offshore wind technology

As the world searches for cleaner and more sustainable methods of generating electricity, wind power is a technology that has moved centre-stage, due to its growing cost competitiveness with fossil generation in many markets.

Over the past few years, wind has been the fastest growing sector of the power industry, with approximately 40,000 MW of wind generating capacity installed worldwide. New technologies have played a major role in sparking global acceptance of wind power. Larger wind turbines will bring economies of scale to the wind industry, helping to make wind power costs more competitive with conventional power generation options. In addition, sophisticated control capabilities are increasing the productivity and grid reliability of today's wind turbines.

Because winds are stronger and more abundant at sea, offshore wind farms offer an even greater potential for increasing the world's supply of renewable energy. Built, owned and operated by GE, the Arklow Bank wind park in the Irish Sea is the first large-scale offshore wind energy facility developed solely as a technology demonstration and learning platform for offshore wind power.

The Arklow project features seven GE 3.6-MW wind turbines – each taller (above water level) than a 30-story building, with rotor blade tip-to-tip dimensions that sweep the size of a football field. These machines – believed to be the first wind turbines over 3 MW designed specifically for offshore applications – add 25 MW of wind-generated capacity to Ireland's power grid.

The latest evolution of GE's wind turbine technology was recently announced. Joining the company's 2.x MW series are the 2.5-MW and 3-MW wind turbines, which introduce a number of industry innovations, including a permanent magnet generator with full power conversion and advanced controls.

In addition to the 3.6 and 2.x MW class machines, GE Energy's wind product line also features the 1.5-MW wind turbine, one of the world's most widely used megawatt-class wind turbines. More than 3,200 of these units have been installed worldwide to date.

## Photovoltaics

Technology is also driving growth in solar energy, by refining the designs and continuing to lower the costs of photovoltaic (PV) solar panels.

Harnessing the power of the sun to provide low-cost energy is more attractive at present than ever before. With today's technology, solar-powered homes no longer need to have large, distracting panels cluttering their rooftops. New, roof-integrated solar panels blend seamlessly with the roofline to maintain the architectural integrity of the home.

GE's installed photovoltaic systems globally generate enough electricity each year to power the equivalent of 12,000 homes, and can displace $CO_2$ emissions equal to the amount of $CO_2$ absorbed annually by more than 22,000 acres of forest. The company has developed a roof-integrated solar power system that can help homeowners realise savings of up to 60% on their monthly energy costs. For commercial applications, GE supplies larger systems such as the solar power modules installed at Shafer Vineyards in Napa, California – the first winery in the US to move to 100% solar power.


The first LMS100 gas turbine package prepared for testing at GE Energy's Houston facility

vide five of the machines to East Kentucky Power Cooperative of Winchester, Kentucky.

GE also has launched the fourth significant rating increase of its LM2500 aeroderivative gas turbine technology. The LM2500+G4 offers 46,000-shaft horsepower and 34.3 MW of output, and will deliver up to 12% more power when compared to its predecessor over a wide range of operating conditions.

## Gas engines

GE Energy's Jenbacher gas engine division, based in Jenbach, Austria, is one of the world's leading manufacturers of gas-fuelled reciprocating engines, packaged generator sets and cogeneration units for power generation. It is one of the only companies in the world focusing exclusively on gas engine technology. Its engines range in power from 0.25 MW to 3 MW and offer versatility, durability and reliability, while meeting all relevant international emission standards.

Since the late 1970s, GE's gas engine division has been developing engine technology to utilise 'speciality gases', including landfill and coal mine methane gas, gas from biomass, sewage gas, and combustible industrial waste gases. Due to fluctuating gas qualities, including varying levels of contaminants, it is still a major challenge to consistently meet international emission standards. It is the need to increase the effectiveness of utilising these gases that is driving the demand for additional enhancements in gas engine technology.

With increased international attention on the environment and the decline in fossil fuel reserves, gas engines can help owners/operators mitigate their emissions and use available energy sources more wisely. Therefore, landfill methane gas and biogas, as 'renewable' fuel sources, are among the attractive alternative fuels that can be used to run gas engines for power generation. For example, landfill methane has 21 times the greenhouse warming potential of carbon dioxide ($CO_2$), the gas most closely associated with climate change.

Such applications also make sense economically, since a 'free' source of energy is being utilised for on-site operations or for the public grid instead of being vented or even flared off.

## Biogas

Biogas is produced from the anaerobic digestion of organic substances, including from the agriculture, foodstuff or feed industries. The resulting gas, produced by micro-organisms in the biomass digester, consists mainly of methane (50% to 70%) and $CO_2$, creating optimal conditions for combustion in a gas engine. In addition, the use of biogas as a '$CO_2$ neutral' fuel offers the operator the opportunity to reduce greenhouse gas emissions.

In 2005, GE's gas engine business supplied Protein & Energie Soltau (ProEn) of Germany with three of its JMS 420 GS-B.LC cogeneration systems for one of Germany's largest biogas energy plants in terms of total output. Commissioned in July, the plant's electricity output of 4.2 MW is fed into the regional grid, qualifying for fixed feed-in tariffs based on the German Renewable Energy Law. The thermal output of 4.3 MW is used to support an integrated yeast-production process, which produces yeast for use in the feed and food industry. More than 370 Jenbacher biogas systems, with a total electrical output of over 230 MW, are currently in operation worldwide.

## Landfill gas

Landfill gas is created during the decomposition of organic substances and consists of methane, $CO_2$ and nitrogen. Use in gas engines allows the methane to be continuously extracted and processed under controlled conditions, reducing the amount of gas that can migrate or escape into the atmosphere. With a calorific value of about 5 kWh/Nm³, landfill gas constitutes a high-value fuel for gas engines that can be effectively used for power generation.

The ability to use landfill gas in Jenbacher engines allows operators to convert a problem waste gas to an energy source. As an example, in 2004, GE's gas engine business supplied Italian municipal waste company AMIAT with six of its JGS 420 GS-L.L generator sets with a total power output of 8.4 MW. The six units are being used at the Basse di Stura landfill, one of Italy's largest landfills, located near Turin in north-western Italy. GE Energy has more than 1,000 Jenbacher landfill gas systems installed throughout the world, with a total output capacity of 950 MW.


GE Energy's 45-kW commercial solar system on the roof of GE's European Global Research Center in Garching, near Munich, Germany

# Offshore oil projects: finance to first oil

## Monday 7 November 2005

The Energy Institute (EI) and the Consilience Energy Advisory Group (CEAG) are pleased to invite you to a 1-day conference at the Energy Institute, 61 New Cavendish Street, London, W1G 7AR.

The conference examines both fundamental aspects of offshore oil project profitability and current industry and market developments. The conference considers four key aspects of offshore oil projects from finance to first oil:

- the rising cost of reserves and development
- financing the project
- project execution risk issues-managing the physical project
- managing investor expectations

The context for the examination is:

The positive factors

- high oil prices
- new technologies
- hard-won discipline in project management

The negative factors:

- escalating reserve acquisition and development costs,
- a scarcity of service company resources
- instability in the planning variables of price, costs and timing

The conference investigates the fundamentals of profitable project management. It also reviews the extent to which the benefits of the current high oil price environment, which has re-valued existing reserves, is inhibiting the development of new reserves.

### Programme

**09.00–09.30: Coffee and Registration**

09.30–09.40: *John Walmsley*, CEAG – Introductory remarks

09.40–10.20: *Mike Bridden*, Harrison Lovegrove – Exploration/acquisition/development: comparative costs

10.20–11.00: *Professor Alex Kemp*, Economic/Fiscal analysis of international contractual structures

**11.00–11.30: Coffee**

11.30–12.10: *Jason Fox*, Herbert Smith – Financing and negotiation of oil based lending

12.10–12.45: *Liz Bossley*, CEAG – Managing price risk using forward curve financing

**12.45–14.00: Lunch**

14.00–15.00: *Ron Bryans*, International Project Director – Project execution risk – managing the project

**15.00–15.30: Tea**

15.30–16.10: Contractor, TBA – Current contractor perspectives

16.10–16.40: *Patrick d'Ancona*, M:Communications – Communicating your performance – managing investor expectations

16.40–17.00: *John Walmsley*, CEAG – Q&A

All speakers have senior current experience in their subjects. For full biographies please visit this link.
**http://www.energyinst.org.uk/content/files/spkbio.pdf**

The course fee is £450.00 (£528.75 inc VAT) for the first delegate from each company. In the event that more then one delegate from a company wishes to attend the event, the fee for each delegate from that company will be reduced to £400.00 (£470.00 inc VAT).

For further ifomation and to book attendance at this event, please contact **Jacqueline Warner, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK. t: + 44 (0) 20 7467 7116, f: + 44 (0) 20 7580 2230, e:** jwarner@energyinst.org.uk

## Automotive Lubricants Reference Book

*Roger F Haycock and John E Hiller (Professional Engineering Publishing, Northgate Avenue, Bury St Edmunds, Suffolk IP32 6BW, UK. t: +44 (0)1284 763277; f: +44 (0)1284 718692; e:* **orders@pepublishing.com www.pepublishing.com***). ISBN 1 86058 471 3. 737 pages. Price (hardback): £120 (+10% delivery charge outside the UK).*

Much of this book focuses on engine oils, although other automotive lubricants such as transmission oils and greases are considered. Considerable attention is given to specifications and oil approval systems, while the relationship between test methods and formulation technology is also covered. Now in its second edition, this publication has been revised and updated to take into account the continuing drive for improvements in the environment, particularly air quality, and consolidation within the oil and petroleum additives industries.

## Shipping Profitability to 2015: The Outlook for Vessel Costs & Revenues

*(Ocean Shipping Consultants, Ocean House, 60 Guildford Street, Chertsey, Surrey KT16 9BE, UK. t: +44 (0)1932 560332; f: +44 (0)1932 567084; e:* **info@osclimited.com www.osclimited.com***). Price: printed version – £850 ($1,600); electronic (pdf) version – £850 ($1,600); printed and electronic versions – £995 ($1,850).*

This study analyses the development of costs and profitability of bulk carriers, tankers, containerships, general cargo vessels and LPG carriers throughout the period to 2015. The past two to three years have seen extensive developments in certain operating cost categories – particularly with regard to insurance and repairs – and this report serves to highlight the scale of such changes.

## Neurological Assessment Aid

*(International Marine Contractors Association (IMCA), 5 Lower Belgrave Street, London SW1W 0NR, UK. t: +44 (0)20 7824 5520; f: +44 (0)20 7824 5521; e:* **publications@imca-int.com www.imca-int.com/publications/***). Price: £10 for IMCA members; £50 for non-members*

This video from the IMCA demonstrates the neurological assessment of a diver. Also available as DVD/CD set, with accompanying notes, the intention is not to set out detailed instructions, but rather to aid format training on the subject. It is intended as an introduction to the start of structured training on such assessments, but can also be used in refresher training. In the interests of being able to use and interpret standardised procedures worldwide, the guidance is based on the examination detailed in the *US Navy Diving Manual*.

## Banking on Baghdad*

*Edwin Black (John Wiley & Sons, The Atrium, Southern Gate, Chichester PO19 8SQ, UK. t: +44 (0)1243 770668; f: +44 (0)1243 770638; e:* **publicity@wiley.co.uk www.wileyeurope.com***). ISBN 0 471 67186 X. 471 pages. Price (hardback): £19.99.*

The continuing instability in Iraq, the debates about the efficacy of the recent war, and the timing of democratic elections mean that Iraq is an issue that is not going to go away. However, the situation is far more complex than many of us can comprehend and, in order to fully understand how we got here, this book looks at the latest events as part of a 7,000-year-long history of commerce, war and conflict taking place in the 'Cradle of Civilisation'. Among the events detailed are a dramatic unveiling of the story behind the Red Line Agreement negotiated by the reclusive billionaire C S Gulbenkian and Turkish Petroleum, Shell and Anglo-Persian Oil; and detail of British involvement in the supply of oil to the Nazi regime during the Second World War.

**Held in EI Library*

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# Crisis – avoiding and managing crises

## Wednesday 23 November 2005
## 15.45 – 19.30, Ashurst, Broadwalk House, 5 Appold Street, London EC2A 2HA

This seminar is directed at executives concerned with the management of companies and public authorities facing crises. It will look at how to plan to avoid or minimise the physical effects of crisis, how to ensure that any legal consequences of an event can be minimised and how best to react so as to ensure that the effect of any event on share price is minimised.

Speakers include:

*Jeremy Larken* – Jeremy is managing director of OCTO, one of Europe's foremost authorities on the leadership and management of crisis and emergency situations. Jeremy served previously in the Royal Navy for 33 years to the rank of Rear Admiral as deputy head of the Ministry of Defence's crisis management organisation dealing with military operational contigencies worldwide. He held six major commands through the height of Cold War operations, including *HMS Fearless* during the Falklands Campaign.

*Ian Johnson* – Ian is a Director and Company Secretary of the Wood Group, a company specialising in the supply of equipment to the offshore oil industry. Ian is a lawyer who has held senior positions both in private practice and in industry and has played an active part in the preparation of crisis management plans.

*Tim Reid* – Tim is a partner in the Global Energy Team at Ashurst, a leading international law firm specialising in the energy sector. Tim has advised many organisations in relation to high profile disputes and how to avoid or minimise their effect on share price. Tim also has experience of advising on the preservation and protection of evidence following major public disasters.

**Programme**

15.45: Registration and refreshments

16.00: Welcome and introduction

16.05: *Tim Reid* – Legal aspects of crisis
- obtaining legal advice
- preserving evidence
- corporate manslaughter
- keeping information confidential
- working with the company's PR advisers
- working with the company's insurers

16.35: *Deborah Pretty* – How to minimise the effect of a crisis on your share price

17.05: *Ian Johnson* – The private sector perspective

17.35: *Jeremy Larkin* – Crisis management
- Avoiding crisis in the first place
- Managing crisis

Q&A

18.15: Drinks

This event is free to attend. To book your place, please complete this form in BLOCK CAPITALS and return it to the address below:

**Jacqueline Warner, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK.**
**t: + 44 (0)20 7467 7116, f: + 44 (0)20 7580 2230, e:** jwarner@energyinst.org.uk

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Last chance to book

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# Oil Depletion – Facing the challenges

**Wednesday 2 November 2005**
**Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK**

There is mounting concern that global oil supplies may peak in the near future. How realistic is this and where will incremental supplies come from? What are the implications for the transportation sector especially for cars and other road transport?

In this important and timely conference industry experts will explain the current oil supply challenges and detail the potential of alternative supplies such as the Canadian Oil Sands. Recent developments in improving vehicle and fuel technologies will also be addressed in an exciting programme that offers both answers and a debating forum.

**Confirmed speakers:**

- **Martin Fry,** Director, Martin Fry and Associates
- **Chris Skrebowski,** Editor, ***Petroleum Review***
- **Roger Bentley,** Senior Research Fellow, Department of Cybernetics, The University of Reading
- **Claire Durkin,** Head of Energy Markets Unit, DTI
- **Jason Nunn,** Director, Upstream Services, PFC Energy
- **Robert Skinner,** Director, OIES
- **Malcolm Watson,** Technical Director, UKPIA
- **Nick Owen,** Senior Manager, Technology, Ricardo UK

**Tickets:**
**Member:**
**£90.00**
**(£105.75 inc VAT)**
**Non-Member:**
**£130.00 + VAT**
**(£152.75 inc VAT)**

**For further information or to book a place at this event please contact:**

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**EI Events Organiser,**
**Energy Institute,**
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