JANUARY 2005

Petroleum review

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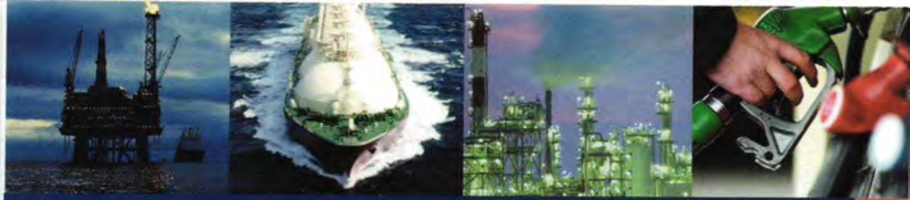
ABBREVIATIONS

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

Front cover pictures: The EI Awards 2004 winners and statues (see p22).
Photos: Jim Four



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Nine to watch in 2005

At the considerable risk of being a hostage to fortune, there appears to be around nine key areas that will shape the international oil and gas industry in the coming year.

● The first, and most obvious, is geopolitics. The key concern in 2005 is whether stability will increase or decrease. Successful investment and production operations are only possible when there is a predictable high degree of political stability and law enforcement.

In this context, there are three immediate questions – Will the post-election Iraq settle down enough for investment to occur? Will the current stand-off in the Ukraine be settled peaceably, with Russian gas supplies to Europe remaining undiminished and unharmed? And possibly most important of all – Will the threat from fundamentalist Islamic militants decrease and will the current Saudi regime retain full control of the Kingdom and its oil supplies?

● The next area of interest will be the way the Russian oil and gas industry develops. In 2005 we will see the emergence of the new state-controlled Gazprom-Rosneft behemoth. How will it operate, and what will this mean for foreign investors (actual and potential) in Russian oil and gas? And for production?

Russian oil companies, particularly Lukoil, are seeking to expand overseas. Lukoil is already in Egypt, Colombia, Venezuela, Saudi Arabia and the Caspian. Next year could see it back in Iraq – a possibility that has just been enhanced by Russia's forgiveness of most of the Saddam-era debt to Russia.

● However, it is not just Russian companies that are seeking to expand their oil producing interests around the world. Both China and India have become acutely aware of their rising oil dependence as their economies expand and are seeking to acquire production assets. Their enthusiasm to lock in future supplies has led to some very aggressive bidding and it is all too possible that 2005 will see a scramble for production assets around the world.

● One of the drivers of this asset scramble has been the very rapid demand growth of the last two years. This leads to the question: 'Has oil demand growth moved to a higher trajectory (2.3% in 2003, 3.3% in 2004) or will continuing high prices cool demand back to the 1.6%–1.8% that had been the norm? We now regard the boom years of the 1960s, when post-war reconstruction and the move away from coal produced oil demand growth of 7%/y, as an anomaly to long-run energy demand growth of just under 2%. The question is whether rapid industrialisation and emerging consumerism in China, India and the Asia-Pacific is producing a new anomaly of faster oil demand growth? And, if so, for how long?

● We can probably expect some easing of the supply/demand balance and somewhat easier prices in 2005 as new production comes onstream.

● Following a year of high and rising oil prices, increased investment in new exploration and production is to be expected. How large these are and how successful they are will be one of the key developments to be watched over the next 12 months.

● On the production technology side, 2005 will be a key year in the struggle to maintain production flows from those areas either in decline or close to it. High oil prices, if maintained, will justify considerable investments in this area. Companies have shown their ability to augment reserves by field extensions and additions, as well as by improved recovery. What they now have to demonstrate is that these 'late life' reserves can be produced at flow rates that are both economic and in volumes sufficient to build overall production to meet market requirements.

● Another key area is going to be North American gas. Latest reports indicate that the current record drilling activity in Canada and the US has managed to stabilise production after declines earlier in the year had reached 4% in both countries. The question will be whether this can continue, how quickly the LNG imports can build up, and how much of the market is going to be destroyed before the new price-weakening supplies arrive?

● On the refining side, 2005 will see a further tightening of fuel qualities around the world. With incremental crude supply largely high-sulphur, there seems to be the possibility of a sulphur squeeze unless there is considerable investment in desulphurisation capacity.

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 UK Health and Safety Executive (HSE) has published new guidance designed to help directors and senior managers in major hazard industries to improve the effectiveness of their leadership. The guidance also aims to encourage senior managers to reflect on their current approach and challenge them to continuously improve health and safety performance in their companies. Visit **www.hse.gov.uk** for more details.

Energy Minister Mike O'Brien has published the UK government's plans for the review of the Renewables Obligation (RO), which ensures all electricity suppliers produce a specified and increasing amount of energy from renewable sources. The detailed proposals on the terms of reference for the 2005–2006 Renewables Obligation Review can be found at **www.dti.gov.uk/energy/renewables/policy/terms_of_reference.shtml**

North Sea oil and gas activity has seen a notable turn-around over the past 12 months but remains vulnerable nonetheless and will only be sustained by continued and substantial investment from the oil companies, a stable and predictable fiscal regime and a continuous and constructive engagement with the government, UKOOA has warned. In a report entitled *Succeeding in a Challenging Environment* – published in November in response to calls for the imposition of further taxes on the industry – UKOOA points to the evidence of investor confidence returning to the North Sea following the introduction of the 40% corporation tax rate for UK oil and gas producers in 2002. The report can be downloaded from **www.oilandgas.org.uk/issues/economic/succeeding.pdf**

The UK Health and Safety Commission (HSC) is seeking views from the petroleum and road haulage industries on proposals for new regulations covering the transport of petrol (the loading of tankers, their carriage and unloading) by road and rail. The draft regulations are designed to be short and straightforward and will be known as the Tank Vehicles (Loading and Unloading of Petroleum-Spirit) Regulations. The draft legislation would replace existing regulations covering the safe transportation of petrol by tanker and is set out in a consultation letter, which is available from the HSE website at **www.hse.gov.uk/consult/live.htm**

UK

***Kerr-McGee reports that it has** brought onstream the UK North Sea James field six weeks ahead of schedule and within budget. In excess of 8,000 b/d of oil is being produced from a single well as a subsea tieback to the Janice CEA floating production facility (which handles some 10,000 b/d).*

***Halliburton is understood to be** selling its 50% stake in UK subsea engineering contractor Subsea 7 to joint venture partner Siem Offshore for $200mn.*

EUROPE

***A high level of development activity** on the Norwegian Continental Shelf is expected in the near future. This follows from a press release from the Ministry of Petroleum and Energy that states that seven plans for operation and development are expected to be delivered during the next six months. These seven projects contain more than 40mn cm of oil reserves and 40bn cm of gas.*

***Norsk Hydro has awarded Aker** Kværner Offshore Partner a NKr90mn modification contract to enable the Øseberg field centre to inject all produced water (a maximum of 20,000 cm/d) from the platform into the Utsira reservoir. The injection system will be installed during 2005.*

***Dong, Denmark's state-owned oil** and gas company, has acquired BP's 10.3% stake in the Ormen Lange gas field offshore Norway for $1.2bn (920mn).*

***Norsk Hydro and its partners have** submitted a plan for development and operation (PDO) for gas export from the Njord field. The field is expected to produce some 2.2bn cm/y of gas from 1 October 2007.*

EASTERN EUROPE

***JKX Oil & Gas has been awarded an** onshore exploration licence located immediately adjacent to the Mashivske field, one of the largest producing gas condensate fields in Ukraine, reports* Stella Zenkovich.

NORTH AMERICA

***Halliburton, Pipeline Engineering,** Westport Technology, Subsea 7,*

Industry first in Eastern Gulf of Mexico

In what is claimed to be an industry first, five independent exploration and production companies and a midstream energy company have come together to facilitate the development of multiple ultra-deepwater, natural gas discoveries in the previously untapped Eastern Gulf of Mexico.

Independence Hub, an affiliate of Enterprise Products Partners (EPD) and the Atwater Valley Producers Group (which includes Anadarko Petroleum, Dominion Exploration and Production, Kerr-McGee, Spinnaker Exploration and Devon Energy) have executed agreements for the dedication, processing and gathering of natural gas and condensate production from six natural gas fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas of the deepwater Gulf of Mexico. As part of the transaction, the producers also have dedicated future production from a number of undeveloped blocks in the area for processing and gathering.

Enterprise will design, construct, install and own Independence Hub, a 105-ft deep-draft, semi-submersible platform with a two-level production deck, which will be capable of processing 850mn cf/d of gas. The platform, which is estimated to cost approximately $385mn, will be operated by Anadarko, and is designed to process production from the six anchor fields and has excess payload capacity to tie-back up to 10 additional fields.

Independence Hub will be located on Mississippi Canyon block 920, in a water depth of 8,000 ft. First production is expected in 2007.

Under the terms of the agreement, the development will include dedicated anchor fields, Atlas and Atlas NW (Lloyd Ridge blocks 5/49/50), Jubilee (Atwater Valley blocks 305/349 and Lloyd Ridge blocks 265/309), Merganser (Atwater Valley blocks 36/37), San Jacinto (DeSoto Canyon blocks 618/619), Spiderman (DeSoto Canyon blocks 620/621) and Vortex (Atwater Valley blocks 217/261 and Lloyd Ridge blocks 177/221), in addition to future discoveries on surrounding undeveloped blocks. The fields will be tied-back to the platform through producer-owned subsea flowline systems. The fields' water depths range from 7,800 to 9,000 ft.

Enterprise has awarded a number of key contracts:

- **Atlantia Offshore for hull and mooring systems design, fabrication, construction and dry transportation to the staging site at Ingleside, Texas.**
- **Heerema Marine Contractors for hull and mooring systems transport and installation.**
- **Alliance Engineering for topsides engineering.**
- **Kiewit Offshore Services for topsides fabrication and installation on to the hull.**
- **Allseas USA for installation of the gas pipeline.**

Additionally, Enterprise will own, install and operate 140 miles of 24-inch pipeline, with a capacity of approximately 850mn cf/d, named Independence Trail. The pipeline, which is estimated to cost $280mn, will redeliver the production from Independence Hub into the Tennessee Gas Pipeline located in West Delta 68.

UK Dana deal

Dana Petroleum has signed an exchange agreement with Caledonia EU under which Dana will acquire a 27.78% interest in the producing Johnston gas field and associated UK North Sea blocks 43/27a and 43/26a. In exchange, Dana will transfer a 30% stake in blocks 23/16c, 23/16d and 23/17 and pay a balancing cash consideration at completion. Block 23/16c contains part of the Barbara gas discovery. On completion, Dana's North Sea gas production is expected to rise by some 17mn cf/d (2,800 boe/d) and add some 37bn cf of gas reserves to the company's portfolio.

BG licence acquisitions

BG Group is to acquire, for $2mn, a proportion of Paladin Resource's interests in three licence areas in the Norwegian North Sea. The blocks lie adjacent to the UK-Norwegian median line immediately north of the BG 100% owned and operated PL297 blocks 1/2, 1/5 and 1/6 located in the Central Graben area of the Norwegian North Sea.

Under the arrangement, BG will acquire an initial 30% in PL 143, 20% in PL 143CS and 20% in PL 298. In addition, BG will acquire a further 10% of PL 143 dependent on future exploration activity.

Granherne, and KBR have joined forces in an integrated service alliance. The new SureStreamSM Flow Assurance Service aims to resolve some of the most challenging problems in the industry.

BHP Billiton (44%, operator) has con- *firmed a commercial hydrocarbon discovery with its Shenzi-3 appraisal well on Green Canyon block 653 in the Gulf of Mexico. The find is some 14 km north-west of the company's Atlantis field.*

MIDDLE EAST

Saudi Aramco is reported to have made *a new gas discovery in the Kingdom's Eastern Province. Gas flowed from the Madraka 1 well at a rate of 38mn cf/d, together with 1,650 b/d of condensate. The find is located some 30 km south of Al-Ghawar gas field.*

Saudi Arabia is reportedly planning a *14% increase in production capacity to 12.5mn b/d. No details of how this would be achieved have been released so far.*

RUSSIA/CENTRAL ASIA

TNK-BP was reported to have taken a *lead in Russian oil production, producing some 231,900 tonnes on 29 November 2004 (taking into account its 50% interest in Slavneft). Lukoil and Yukos produced 231,700 tonnes each.*

Sakhalin Energy reports that a signif- *icant milestone in the Sakhalin II Phase 2 project has been reached with the completion at Vostochny in Russia of the main concrete construction work on the huge gravity base substructure (CGBS) for the Lunskoye offshore gas production platform. A second CGBS for a new Piltun offshore platform is also under construction at the site in Vostochny.*

Arawak Energy reports that tests *indicate the Duvanny 104 well in Azerbaijan should be able to sustain a stable gas flow of 1.2mn cf/d. Together with wells worked over in 2001 and 2003, total shut in production currently stands at 3.7mn cf/d – sufficient to justify investment in gas processing facilities. First gas sales are anticipated in 1H2005.*

Uzbekistan's Uzbekneftegaz (10%) *and Russia's Lukoil (90%) have officially ratified the 35-year production sharing agreement (PSA) for the Kandym-Khauzak-Shady gas project in south-west Uzbekistan. Total*

Fabrication first for sleeper cabin

Duffy and McGovern claims to have become the first company to bring a fully compliant 12-man offshore sleeper cabin on to the market. The new unit, which represents an investment of over £500,000 by the accommodation firm, is said to be the first unit of its size to comply with SOLAS (Safety of Life at Sea), IMO (International Maritime Organisation) and fire-test-procedure (FTP) requirements.

'A revised internal layout means that the new cabin also offers the most flexible temporary offshore accommodation to date, being capable of sleeping either eight, 10 or 12 men and bringing a new level of comfort and convenience to sleeper units of this size,' states the company. 'The new layout and removable bunks mean customers can substantially increase their manning levels offshore on a temporary basis using the cabins already on deck. It would, for example, be entirely feasible to comfortably accommodate from 24 up to a maximum of 36 men in just three of these new modules.'

Each module is split into two bedrooms which contain a minimum of four beds as standard, but which come with a further two bunks that can be easily fitted and removed as required by the customer during the hire period. Unlike earlier 12-man cabins, the new modules also benefit from two wet areas – one within each six-bunk bedroom – and an additional wash hand basin, providing greater privacy and convenience. The A60 modules will be available in three sizes – 33 x 13 ft, 34 x 11ft and 36 x 12 ft - are fitted with fire and gas detection systems and have all hook-up services conveniently located in the centre of the module for quick connection to the host installation.

The modules have been designed with the Americas and West Africa region in particular in mind and are now available for rental or lease/ purchase.

Bibiyana gas field development agreement signed

Unocal has signed a natural gas purchase and sales agreement (GPSA) with Petrobangla to develop and produce natural gas from the Bibiyana field in Bangladesh's block 12. Under the agreement, Unocal's minimum production will be 200mn cf/d from the field, beginning in 4Q2006. The government of Bangladesh has indicated that it intends to nominate between 250mn and 300mn cf/d. Minimum production sales volumes under the GPSA increase to 400mn cf/d at the end of 2008.

Total development cost for the project, including up to 15 development wells, has been estimated at $230mn. Unocal plans to build a gas processing plant with an initial capacity of 300mn cf/d. The plant capacity is expected to expand to approximately 600mn cf/d as field production ramps up. The development plan also includes two pipelines to connect the Bibiyana field to the national distribution grid.

Unocal, through subsidiaries, is producing 180mn cf/d of natural gas from the Jalalabad field on block 13. In 2Q2005, completion of the Moulavi Bazar field development is expected to add another 70mn to 100mn cf/d of production. Both of these fields produce gas for sale to Petrobangla. In total, Unocal subsidiaries currently supply almost 15% of Bangladesh's natural gas requirements.

Chinese first oil

CNOOC (51%) reports that the Huizhou 19-3/2/1 fields in blocks 16/08 and 16/19 of the South China Sea have produced first oil from well Huizhou 19-3-1 at an initial rate of 6,500 b/d.

Development of the fields is via two platforms, 14 wells and a subsea pipeline from platforms to the FPSO Nanhai Faxian.

At peak production, the fields are expected to produce some 45,000 b/d of oil. The blocks are operated by CACT Operators Group – a consortium comprising state-owend CNOOC, Eni and ChevronTexaco.

Rosetta deal completes

BG Group reports that its acquisition of Shell's 40% stake in the BG-operated Rosetta concession in the Nile Delta, Egypt, has completed – giving the group a total interest of 80%. Edison holds the remaining 20%.

Rosetta started production in January 2001 and supplies the domestic market. Phase Two of the development will consist of an unmanned minimum facilities wellhead platform tied back to the existing Rosetta platform.

First gas from the Phase Two project is scheduled to commence in 2005.

proven reserves are put at some 283bn cm of gas. Kandym is the largest field, with more than 150bn cm of gas. Annual gas production is expected to peak at about 9bn cm, with total production of some 207bn cm. The project is due onstream in 2007.

ASIA-PACIFIC

***Australia has formally requested** extended jurisdiction over its submarine continental shelf beyond the standard 200 nautical miles, granting exclusive rights over oil and gas deposits, reports* Keith Nuthall.

***Tullow Oil, as operator of block 9,** reports that the three lowermost zones of the reservoirs encountered by the Bangora-1 well in Bangora, Bangladesh, flowed in excess of 120mn cf/d of gas. The well will be suspended as a future producer.*

***BHP Billiton is to sell its interests in** the Woodside-operated Laminaria and Corallina oil fields in the Timor Sea to Paladin Oil & Gas for $150mn. BHP Billiton currently holds a 32.6% stake in Laminaria and 25% in Corallina.*

LATIN AMERICA

***Lukoil and Venezuela's state-owned** PdVSA have signed a memorandum of understanding under which the Russian company will become involved in new upstream projects in the Orinoco heavy oil belt in the Gulf of Venezuela, as well as taking part in rehabilitation, enhanced oil recovery and productivity increase projects on depleted fields. Lukoil may also become involved in joint refining projects under the agreement.*

AFRICA

***Equator Exploration of Sao Tome e** Principe is looking to raise up to £20mn through an Alternative Investment Market (AIM) listing to explore for oil in two 4,000 sq km deepwater blocks, reports* Stella Zenkovich.

***The National Oil Company of Liberia** (NOCAL) has received bids from six foreign oil companies to carry out oil exploration in the country, reports* Stella Zenkovich. *Those bidding include Woodside from Australia, Respol of Spain, Regal of the UK, Oranto based in Nigeria and the UK,*

Auzzie Blacktip gas supply agreement signed

Woodside Energy (53.85%, operator) and Eni (46.15%) have signed a gas sales agreement with Alcan Gove under which Alcan will buy 800 petajoules of gas from the Blacktip gas project in Australia's Northern Territory. The annual contract quantity is for 44 pJ/y and, depending on actual offtake volumes, the contract duration could be up to 20 years. The agreement is conditional on Blacktip receiving all joint venture and government approvals by mid-2005 and pipeline arrangements being concluded.

The Blacktip project includes the development of the Blacktip gas field in the Joseph Bonaparte Gulf in exploration permit WA-279-P. It involves the installation of a remotely operated wellhead platform and a 110-km subsea pipeline to an onshore gas plant near Wadeye in the Northern Territory. First gas is expected in late 2007, with sales gas transported from Wadeye by the proposed 940-km Trans Territory Pipeline to Gove.

Structural analysis solutions alliance

Stavanger-based Roxar, a leading technology solutions provider to the upstream oil and gas industry, reports that its Software Solutions division has signed a technical cooperation agreement with Rock Deformation Research (RDR), an established market leader in structural geology which operates as a consultancy company and research group based at the University of Leeds, UK. Under the terms of the agreement, RDR will use Roxar's industry leading Irap RMS reservoir modeling software as its preferred tool for 3D geological modeling and associated consulting projects. The Irap RMS software platform will provide RDR with a flexible solution allowing it to incorporate its own methods of structural and fluid flow analyses (eg fault and fracture behaviors) into an integrated reservoir modeling workflow solution.

Through its sales and marketing groups, Roxar will also partner with RDR on the integration and commercialisation of their technology and look to bring joint structural analysis products and solutions to market. Roxar and RDR are currently working together to extend Roxar's upcoming fault seal analysis module with new techniques developed by RDR. This, together with other packages being planned, will allow geologists and engineers to better characterise the potential impacts of faulting on oil and gas reservoirs.

Faroese licensing round closed

The deadline for submitting applications for exploration licenses in the second licensing round on the Faroese Continental Shelf expired on 17 November. The Faroese Petroleum Administration has received nine applications from eight companies, which are organised in five groups or individual companies.

The area offered for licensing covers some 19,000 sq km and is divided into 83 whole blocks and 39 part blocks. The main area lies to the east and south-east of the Faroes, while two smaller areas lie to the south-west.

The following oil companies have submitted licence applications: Atlantic Petroleum, Chevron Texaco, Dong, Faroe Petroleum, Geysir Petroleum, OMV, Shell and Statoil.

Kerr-McGee interest in Blind Faith

Kerr-McGee is to acquire BP's 37.5% working interest in the Blind Faith discovery in the deepwater Gulf of Mexico plus additional cash consideration in exchange for Kerr-McGee's interests in various oil and gas assets in the Arkoma Basin of south-east Oklahoma.

Blind Faith is located in 7,000 ft of water on Mississippi Canyon blocks 695 and 696. The discovery well was drilled in June 2001 and encountered more than 200 ft of net pay in Miocene sands from 20,900 ft to 24,300 ft. A successful appraisal well was drilled earlier in 2004. The discovery has an estimated gross resource potential exceeding 100mn boe. ChevronTexaco operates Blind Faith with a 62.5% working interest. Development options are currently being evaluated and sanction is expected in 2005 with first production in 2007.

Obekpa of Nigeria and UK-based Oceanus.

***A recent World Bank report on Opec** has disclosed that about 80% of Nigeria's oil and natural gas revenues accrues to just 1% of the country's population, writes* Stella Zenkovich. *The remaining 99% of the population receives the other 20%, leaving Nigeria with the second lowest per capita oil export earnings – put at $212 in 2004. This figure compares with $589 per person earned in 1980, the peak year for Nigerian oil export revenues.*

***Amerada Hess has reported that the** G-19 exploration well drilled offshore Equatorial Guinea on block G in the Rio Muni Basin has made a new oil discovery, encountering 113 ft of net oil pay in the Campanian.*

***Total has made a gas discovery on** the Timimoun permit in Algeria, located 500 km south of Hassi R'Mel. The Iraharen 5 well tested at a rate of 17.5mn cf/d of gas.*

***Woodside Energy reports that the** government of Mauritania has exercised its right to participate in the Chinguetti offshore oil field development. The government will take a 12% stake.*

WORLD

***Offshore oil and gas production is** forecast to grow from 39mn boe/d in 2004 to 55mn boe/d by 2015. From providing around 34% of total global production in 2004, offshore oil is expected to reach 39% by 2015. The complete costs to explore for, develop and operate offshore oil and gas fields, presently some $111bn, are forecast to total $1,440bn over the next decade. According to* The World Offshore Oil & Gas Forecasts, *published by industry analysts Douglas-Westwood and using information from the 'Energyfiles' database.*

***Opec has cut its estimate for the** growth in world demand this year and next as high prices impact economic growth. World consumption is forecast to increase by 2.5mn b/d, or 3.2%, this year to 81.74mn b/d – some 120,000 b/d lower that the cartel's previous forecasts. Demand in 2005 is expected to grow by 1.49mn b/d, or 1.8%, compared with the 1.61mn barrel, 2% gain Opec forecast earlier.*

New upstream software solution launched on market

Accenture and SAP have jointly designed and developed the composite application SAP® xApp™ Integrated Exploration and Production (SAP xIEP), which is powered by the SAP NetWeaver™ technology platform. SAP xIEP allows upstream energy companies to integrate critical knowledge, data and applications – including those for development, production, operations and maintenance activities – to better execute key upstream oil and gas processes.

By offering users the ability to easily access and leverage industry processes and information as well as conduct transactional processing across the numerous and often-disparate systems used in upstream operations, SAP xIEP is claimed to significantly reduce the amount of time that energy professionals spend searching for data or reconciling integration issues. As a result, they can make smarter and faster decisions, produce accurate and transparent information, increase adherence to operational processes, and increase productivity.

'The digital oil field is both a solution and a problem,' said Dan Miklovic, Vice President and Research Director, GartnerG2. 'It produces more data than ever before, but oil companies must learn how to make the most of all that new information.'

SAP xIEP is designed to support critical upstream business processes, starting with upstream asset maintenance. Support for this process includes classifying and prioritising maintenance work, reducing recurring maintenance and high-impact failures, optimising inventory levels and availability of critical parts, predicting equipment failures and unplanned maintenance activities, and accelerating response times to internal and external partners.

Shell sells some GoM pipeline assets

Shell US Gas and Power has entered into a purchase and sale agreement with Enbridge for the sale of Shell Gas Transmission, which includes a majority of Shell's Gulf of Mexico natural gas pipeline business, for $613mn. The sale is part of Shell's ongoing programme to grow its upstream business and focus on core downstream activities.

Shell Gas Transmission owns or has an interest in 11 Gulf of Mexico natural gas pipelines in operation or under construction with a combined landed capacity of some 4.7bn cf/d. The business has assets located across the Gulf of Mexico production areas. Shell's exploration and production business will retain select gas gathering assets, which are viewed as integral to continued optimisation of its existing developments and production.

Anadarko plans for output growth

Anadarko Petroleum has approved a 2005 budget in the range of $2.9bn to $3.1bn. Approximately 64% of the total budget is planned for development activities, 25% will go to exploration, and the remaining 11% is set aside for capitalised interest, overheads and other items. The programme is expected to deliver 7–11% production volume growth in 2005 (160mn to 165mn boe) over 2004.

Development spending will focus on Anadarko's continued success in unconventional tight gas plays in the Vernon field in North Louisiana and Wild River in Alberta, Canada, and on delineating new plays in Texas and Louisiana. Production will continue to ramp up at the company's enhanced oil recovery operations at the Salt Creek and Monell fields in Wyoming. In the Gulf of Mexico, Anadarko will focus on delineation drilling and facilities installation in the deepwater at K2, K2 North and the Eastern Gulf of Mexico, which are expected to be significant contributors to the company's volume growth through 2008. In Alaska, it is expanding the Alpine facility to increase capacity.

Venezuela is also expected to generate good volume growth in 2005. In Algeria, the company expects to make significant progress on the development of block 208 discoveries, with new production facilities scheduled to come online in 2007.

The exploration budget will focus on a number of key areas in the deepwater Gulf of Mexico, including prospects such as Genghis Khan, Knotty Head and Mondo Northwest. In addition, the company will explore for deep gas objectives in the onshore US and Canada. International exploration will focus on drilling programmes in Algeria, Qatar, Tunisia and Indonesia, as well as activities within the company's targeted new venture areas.

UK

BG Group and its partners in Dragon *LNG – Petroplus and Petronas – have confirmed their commitment to develop a £250mn LNG import terminal at Milford Haven in Wales, which is scheduled to be operational in 4Q2007. The agreements confirm the ownership of the terminal (BG Group 50%, Petronas 30% and Petroplus 20%), as well as the 20-year arrangements governing the use of capacity rights (BG Group 50%, Petronas 50%) allowing BG Group and Petronas to each throughput 3bn cm (106bn cf) of gas per year, from around 2.2mn t/y of LNG.*

EUROPE

The Dutch government, Shell *Nederland and Esso Nederland have agreed in principle on a split of Gasunie, the Dutch gas company, resulting in a transfer of ownership in the transportation business. Under the envisaged arrangement, the Dutch state will assume full ownership of the transportation business, including all assets, operations and participations held by that part of the business. The merchant business will remain a joint venture between the Dutch state (50%), Shell (25%) and ExxonMobil (25%).*

EASTERN EUROPE

Mol, the Hungarian oil and gas com-*pany, has submitted a joint non-binding indicative bid with its 25% Croatian affiliate INA for a stake in Bosnia's largest oil firm Energopetrol, reports* Stella Zenkovich.

OMV is to launch a share capital *increase and convertible bond issue to refinance the acquisition of 51% of Petrom as well as to strengthen its capital base for continued expansion in its core markets.*

NORTH AMERICA

Alberta energy firms Viking Energy *Royalty Trust and Calpine Natural Gas Trust are understood to be planning to merge in a stock swap that would put Viking's management in charge.*

ABS has become the first classification *society accepted into membership to the Society of International Gas Tanker and Terminal Operators (SIGTTO).*

World first for shipping 'Green Passport'

Lloyd's Register has verified what it states is the world's first 'Green Passport' in full compliance with the International Maritime Organisation's (IMO) Guidelines on Ship Recycling for the LNG carrier *Granatina*, operated by Shell International Trading and Shipping Company (STASCo). The vessel is a new LNG carrier, delivered in 2003 by Daewoo Marine Shipbuilding and Engineering in Korea to high safety and environmental standards. The verification was the result of several months of collaborative effort between STASCo's technical management, the ship's crew and Lloyd's Register.

The Green Passport, as defined by the IMO guidelines, is a document that contains an inventory of all the materials onboard a ship which may be hazardous to human health or to the environment which should accompany the ship throughout its operational life. The Green Passport is to be passed by the owner to the ship recycling yard at the end of the ship's life, to enable the yard to formulate a safe and environmentally sound way of breaking the ship.

Phil Lewthwaite, STASCo's LNG Fleet Manager, says: 'While we at STASCo understand the benefit of the Green Passport for ensuring the safe disposal of the ship at the end of its life, we also recognise that there are benefits to be gained from having access to a definitive list of the hazards onboard the ship for all those involved – ourselves as operators, our crew and Lloyd's Register as classification society. This awareness, combined with the appropriate management systems, helps us to minimise the risks we have identified.'

The process involved submission of documents and material specifications to Lloyd's Register for appraisal, leading to the formulation of a draft Green Passport. A survey was then held onboard the vessel while discharging in Portugal to verify the contents of the Green Passport against the vessel. Upon satisfactory completion, the document of compliance and the Green Passport were issued by Lloyd's Register and added to the vessel's records. *Granatina* is now able to display these documents in its survey records. To ensure proper maintenance, the vessel will be subject to annual verification of the Green Passport concurrent with its normal annual surveys.

Latest European Union developments

The European Bank for Reconstruction and Development (EBRD) has confirmed that countries in its eastern Europe and central Asia area of focus are booming because of high oil prices, writes *Keith Nuthall*. Its annual *2004 Transition Report* says Russia and the Ukraine are experiencing 'skyrocketing annual growth', making the former Warsaw Pact the world's second-fastest-growing region (up 6.1%), next to China and its southern neighbours. For more information on the report, visit **www.ebrd.com/pubs/index.htm**

In other EU news:

- The EU Council of Ministers (Energy) has called for talks with Opec over continuing high oil prices. Ministers have also agreed more EU investment is required in the sector, but are opposed to reducing fuel taxes.
- The European Commission has blocked a deal combining Portugal's main power and gas groups over competition concerns. Galp Energia wants to sell 51% of gas firm GdP to former state monopoly EDP and 49% to Italy's Eni.
- The European Investment Bank (EIB) is planning to lend up to 200mn to Endesa Italia to upgrade two large oil-fired plants (320 MWe each) to CCGT (combined cycle gas turbine) systems (800 MWe total capacity) and build an 18-km pipeline to the national gas grid.
- The Commission has referred a proposed joint venture between petrol companies Shell Espana and Cepsa to provide aircraft refuelling services at Spanish airports to Spain's competition authorities.
- A 315 km/h speed record has been set for a car running on biofuels. Using LPG and lubricated by sunflower oil, the IdéeVerte Compétition car was designed with European Space Agency (ESA) technology to protect its parts against heat generated by this low emission fuel.
- The Commission is to simplify the EU directive 75/439/EEC on the disposal of waste oils, parts of which it considers obsolete, imposing procedures entailing 'no material benefit' for member states.
- Brussels has approved Finnish energy company Fortum's shareholding increase to 31% in Finnish gas company Gasum, exceeding a limit 25% imposed by the Commission in 1998.

RUSSIA/CENTRAL ASIA

TNK-BP subsidiary Tyumenneftegaz *(TNG) has begun construction of a 76.5-km oil pipeline to connect the Kalchinskoye field in the Uvat region of Russia's Tyumen Oblast with the Demyanskaya system. The pipeline will have a throughput capacity of 10–12mn t/y of oil, reports* Stella Zenkovich.

The European Bank for *Reconstruction and Development (EBRD) plans to finance the modernisation and expansion of Russian pipeline infrastructure without sovereign guarantees, the bank said in its Russia strategy for 2005–2006, writes* Stella Zenkovich.

Dana is to sell its 10% minority *holding in Russian company Evikhon for $28mn to Sibir Energy.*

Lukoil has sold its Lukoil-Bureniye *subsidiary to Eurasia Drilling Company (EDC) for $130mn.*

ASIA-PACIFIC

Korea Gas Corp (Kogas) is reported *to have secured 6.66mn tonnes of 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 set to sign a spot contract with Malaysia LNG to buy a further 1.2mn tonnes between November 2005 and March 2008.*

LATIN AMERICA

The Clean Development Mechanism *(CDM) of the Kyoto Protocol has approved its first emissions trading project – the NovaGerar landfill gas to energy project in Rio de Janeiro, Brazil. The Netherlands CDM facility will buy 2.5mn tonnes of its carbon dioxide emissions savings at 3.35/t, totalling 8.4mn, reports* Keith Nuthall.

AFRICA

Egypt is expected to become the *world's sixth-largest exporter of liquefied gas according to Sameh Fahmy, the country's Minister of Petroleum – helping boost the country's energy exports to $10bn by 2010, writes* Stella Zenkovich.

Algerian LNG

Sonatrach has awarded Respol YPF (60%) and Gas Natural (40%) of Spain a contract for an integrated LNG project in the Gassi Touil-Rhourde Nouse-Hamra region of eastern Algeria. The two companies will produce gas already discovered in Gassi Touil, Rhourde Nouse and Hamra, and will undertake exploration work in the awarded zone to discover additional oil and gas reserves for subsequent development and production.

A new LNG plant is also to be constructed at Arzew under the agreement. It will have a capacity of 5.2bn cm/y – equivalent to 20% of Spain's domestic consumption – and is due to be commissioned in 2009.

LNG ships for Sakhalin

Sakhalin Energy has awarded contracts to two Japanese-Russian consortiums for the long-term time charter of three newbuilt LNG vessels.

One contract went to a consortium consisting of Nippon Yusen Kabushiki Kaisha (NYK) and JSC Sovcomflot for two 147,200 cm LNG ships constructed at Mitsubishi Heavy Industries with delivery scheduled for 4Q2007.

The second contract went to a consortium consisting of Mitsui OSK lines (MOL), Kawasaki Kisen Kaisha (K Line) and Primorsk Shipping Corporation for a similar sized ship constructed by Mitsui Engineering and Shipbuilding The vessel is slated for delivery by 2Q2008.

Yukos assets to be put up for auction

Shareholders in Yukos are reportedly considering liquidation or filing for bankruptcy after deciding against a rescue plan for the Russian company while its main production arm – Yuganskneftegas – remains up for auction. It is understood that some form of liquidation would avoid the need to sell a large part of the business, which has been threatened by the Russian government, while bankruptcy would allow Yukos to unfreeze its assets and raise much-needed cash.

Share prices were reported to have fallen some 22% to reach $1.6 in the fourth week of November after the government set a December date for the sale of a 77% stake in Yuganksneftegas in order to help pay off Yukos' total tax debt of $24bn.

Gazprom's newly established oil subsidiary, Gazpromneft, was expected to bid for Yukos' Yugansk oil field in Siberia, which is understood to have a starting price of $8.6bn – a figure that Yukos is reported to have said is less than half the market valuation.

Ex-Im Bank loan for Qatar LNG

The Export-Import Bank of the United States (Ex-Im Bank) has approved a loan guarantee of up to $930mn to support the export of US goods and services to Qatar Liquefied II (Qatargas II) to build an LNG project and related offshore and onshore facilities in Qatar. US exporters participating in the sale include Air Products and Chemicals, ExxonMobil, KBR and J Ray McDermott. Qatargas II is a special purpose company owned 70% by Qatar Petroleum, the state oil and gas company of Qatar, and 30% by the US super major ExxonMobil.

Ex-Im Bank support covers a portion of the 15.6mn t/y LNG project, which overall is expected to cost over $7bn. The project involves production of natural gas offshore from Qatar's North Field, two gas liquefaction units, offtake infrastructure at the Ras Laffan Industrial City, LNG ships and an LNG regasification terminal at Milford Haven in the UK.

Gazprom unveils UK gas marketing plans

Gazprom has announced plans that it claims will 'ensure the future security of gas supply in the UK' by providing 10% of the market requirement by 2010. The announcement came as the Russian company expanded its activities in the UK under the name Gazprom Marketing and Trading.

The newly named company – formerly known as Gazprom UK Trading – already has an existing 10% stake in the Interconnector pipeline that runs from Zeebrugge in Belgium to Bacton in the UK. The company is planning further investment in pipeline and storage facilities that are in addition to the existing storage centre in Germany, which is claimed to be the largest in Europe. Gazprom Marketing and Trading has also purchased a new London headquarters for the planned expansion of its workforce.

New climate change forum unveiled in London

The London Climate Change Service Providers Group (LCCSPG) – an organisation that aims to promote the shared interests of service providers in the climate change and emissions trading sectors – was launched by British businesses on 1 December 2004. Elliot Morley, UK Minister for the Environment, spoke at the event.

The market in carbon dioxide and other greenhouse gas emissions is the fastest growing commodity market in the world and is likely to outstrip established markets, such as power, oil and gas, in the scale of its activities over the next few years. Companies active in traditional markets covered by the European Emissions Trading Scheme (ETS), such as energy, metals, cement, pulp and ceramics, by definition, have a stake in the carbon market and will need to factor emerging carbon prices into their future business decision-making.

Emissions trading is one of the three key planks of the Kyoto Protocol, which is designed to encourage countries to cut greenhouse gas emissions in the most economically efficient manner possible. Countries and companies can either cut production, invest in clean technology in developing countries (Clean Development Mechanism), or in developed countries (Joint Implementation) or trade in the emissions market to meet the target emissions cuts proscribed by Kyoto.

The European Emissions Trading Scheme, the ETS, which takes effect from 1 January 2005, is the European precursor of the first Kyoto commitment period of 2008–2012. Signatories of the Kyoto Protocol have committed to cut greenhouse gas emissions by 5%, in aggregate, compared with a 1990 baseline period by 2008–2012 – Europe has agreed to cut by 8% and the UK by 12.5%. The ETS requires the establishment of measurement, verification and registration processes, all of which will also be necessary for the success of the Kyoto mechanisms.

London is already a recognised and influential hub of European emissions trading and promises to be a growing centre for international emissions advice and trading activities, owing to the depth and diversity of its service providers. The UK has operated a number of climate change-focused policies for a number of years, including its own emissions trading scheme since February 2002, and has provided much valuable experience in the operation of the market.

This early start by the UK has pioneered expertise in a new business-support sector. LCCSPG provides a comprehensive range of the necessary support services, from engineering to economics and includes consulting firms, lawyers, accountants, emissions verifiers, traders, brokers, technology providers and market advisors. These companies offer services to both UK and international industry and organisations that require support to manage their new climate change responsibilities quickly and efficiently. This provides the UK with a competitive advantage in the new global market. The European Emissions Trading Scheme is silent on how emissions allowances are to be traded, but the market has produced its own, still-evolving solution, and a forward over-the-counter emissions market is already trading actively. LCCSPG offers practical assistance to that process.

World's largest hydrogen filling station is opened

What is claimed to be the world's largest hydrogen filling station was formally opened in Berlin, Germany, on 12 November. Norsk Hydro supplied the equipment for hydrogen gas production. The Norwegian company has worked with eight other companies in the Clean Energy Partnership (CEP) project, which is supported by the Federal Government of Germany. The aim of the project is to demonstrate that hydrogen can function as an everyday fuel with a view to future sustainable mobility.

The hydrogen station, which is part of the Aral chain, is situated at Messedamm, close to the Berlin central bus station. Hydrogen is produced by a Hydro/GHW electrolyser through splitting water into its two basic elements – hydrogen and oxygen. The electricity needed for this process is provided in the form of renewable power in Berlin. The hydrogen is pressurised and stored. The Hydro electrolyser can be controlled from Norway and will produce hydrogen on demand. It is reported that this production in the middle of the busy city of Berlin gives no emissions at all, apart from oxygen, which is released to the air.

UK

BP has announced a phased exit *from its DF2 and DF3 acids and acetone manufacturing operations at Saltend, Hull, and with it a phased withdrawal from its formic acid, propionic acid and acetone businesses, leading to a reduction in its European acetic acid production capacity. Production on the DF3 unit will cease at the end of April 2005 and on the DF2 unit late 2006/early 2007.*

UK energy regulator Ofgem has *forecast that although some areas will see distribution costs fall by up to 9%, overall, businesses may face up to 12% increases in electricity costs over the next year – with the worst hit areas including south-east England, the north-west and Scotland. The rises are being made in order to fund increased investment in improved efficiency of the electricity network, as well as improving quality of service and accommodating growth in distributed generation.*

EUROPE

BP and NOVA Chemicals Corporation *have reached an agreement in principle to combine their European interests in Styrene Polymers to create one of the largest polystyrene and expandable polystyrene manufacturers and marketers in Europe. BP and NOVA Chemicals will each have a 50% stake. The proposed joint venture, which is subject to a number of regulatory and other consents, is expected to commence during early 2005 and be headquartered in Fribourg, Switzerland.*

BP intends to include two European *oil refineries – at Grangemouth, Scotland, and Lavéra, southern France – in its new olefins and derivatives (O&D) petrochemicals entity. O&D is due to be sold, possibly through an initial public offering (IPO), in 2H2005, subject to market conditions and necessary approvals. There will be no compulsory redundancies associated with the decision to include the two refineries in the O&D company, states BP. The Grangemouth and Lavéra refineries have combined crude oil capacity of 21mn t/y (425,000 b/d) and chemical feedstock output of 2.2mn t/y.*

EASTERN EUROPE

Shell and the Hungarian oil and gas company Mol have signed a sale and purchase agreement for the sale of the shares in Shell Romania, excluding Shell Gas Romania. The divestment includes a network of 59 fuel retail service stations geographically spread across Romania, and the aviation, lubricants, commercial and marine businesses.

Lukoil is understood to have acquired 14 fuel retail outlets in Hungary, mostly formerly owned by Austria's largest privately-owned oil company AVANTI Tankstellenbetriebs, for an undisclosed sum. It has been reported that the Russian company plans to secure a 15–20% share of the Hungarian retail market within three years.

NORTH AMERICA

Centrica has entered into a binding agreement to acquire 100% of the partnership interests in Frontera Generation LP (FGLP), a subsidiary of TECO Energy, for $134mn (£70mn) in cash. FGLP owns the Frontera power station, a gas-fired combined-cycle 477-MW power plant located in the southern region of Texas, within the area served by Centrica's CPL Retail Energy subsidiary. It is the second power station that Centrica has bought in Texas over the past 12 months, following the acquisition of the Bastrop Energy Center in June. As a result, Centrica will be able to meet approximately 25% of projected peak demand in Texas for 2005 from its own assets.

EnCana has signed a memorandum of understanding with the Premcor Refining Group to conduct a preliminary design and engineering study of the modifications necessary to upgrade Premcor's existing refinery at Lima, Ohio, to process an estimated 200,000 b/d of blended EnCana heavy oil supplied under a proposed long-term sales contract. The agreement contemplates the establishment of a 50:50 joint venture which would own and operate the upgraded refinery.

MIDDLE EAST

Oiltanking and Odfjell have signed a contract with the Sohar Industrial Port Company (SIPC) for the exclusive operation of the liquid berthing facilities and the development of a storage terminal in the Port of Sohar

Greater future role for coal-fired generators versus gas turbines

In the future, the role of coal-fired generators will be greater and gas turbines less, according to a new report – *World Fossil Fired Power Individual Country Capacity Forecasts* – published by the McIlvaine Company. The report predicts that US coal-fired capacity will grow faster than predicted by the Energy Information Administration (EIA), a division of the US Department of Energy (DOE). According to the report, the present capacity of 329 GW will expand to 356 GW by 2012.

There are a number of reasons why greater growth is predicted for coal and less for gas turbines, states the company:

- The price of natural gas will remain high.
- The cost of environmental controls for coal-fired plants will be less than anticipated.
- The opportunity to combine biomass gasification as a supplemental fuel for existing coal-fired boilers will boost electricity output and qualify units as renewable energy producers.

World coal-fired capacity is forecast to increase from 1,200 GW in 2004 to 1,450 GW in 2012. Gas turbine capacity is forecast to increase from 649 GW in 2004 to 900 GW in 2012. It should be noted that most coal-fired plants will be base-loaded while many gas turbine plants will operate only at peak hours.

The Department of Energy (DOE) forecasts that in 2012, 40 quadrillion Btu (quads) of gas will be utilised for world electricity generation compared to 76 quads of coal. McIlvaine believes that coal will be more than 80 quads and gas will be less than 36.

A big variable in the forecast is the growth of capacity in China. Coal-fired capacity is projected to grow at 17 GW per year over the next eight years. But the Chinese government has a target to add as much as 30 GW per year of coal-fired capacity. If this is achieved, then the world capacity in 2012 would be 104 GW larger than forecast.

There is also uncertainty in Western Europe due to the impact of the Kyoto Protocol. However, McIlvaine maintains that replacing coal-fired plants older than 20 years (operating at 31% efficiency) with new coal-fired plants (with 45% efficiency) will be the most cost-effective option for carbon dioxide reduction. Thus, Western Europe coal-fired capacity will increase from 154 GW in 2004 to 164 GW in 2012. Investment in new coal-fired plants will be substantially more than the 10 GW differential in capacity due to the replacement factor.

Coal-fired plant capacity in Eastern Europe is forecast to expand from 60 GW this year to 70 GW in 2012. In addition, a number of existing plants will be replaced in keeping with environmental stipulations for new European Union members, states the report.

US grant for fuel cell project

The US Department of Energy (DOE) has selected IdaTech for a $1.4mn award to conduct a three-year programme of fuel cell system research and development targeting off-road vehicle applications. This is the second DOE award granted to IdaTech in the past 14 months.

The objective of the programme is to identify and recommend innovative fuel cell designs to overcome arduous environmental conditions faced by such off-road vehicles as turf and grounds maintenance vehicles, and construction and farm equipment. To date, nearly all work in fuel cell development has focused on stationary and portable applications operating in relatively benign environmental conditions. However, off-road fuel cell power generation and propulsion must take place where vehicles are exposed to such difficult conditions as dust, heat, humidity, shock and vibration. Given the unique nature of these conditions, there is a need for a system designed specifically for such applications.

Led by IdaTech, the programme will include team members from Donaldson Company, a Minnesota-based global leader in filtration systems; the University of California–Davis, offering expertise in the application of fuel cell systems in vehicles; and The Toro Company, a leading manufacturer of utility vehicles, also based in Minnesota. The programme began in December 2004 and is scheduled to be completed by December 2007.

In October of 2003 IdaTech was awarded a $9.6mn development program by the US DOE for the development of a 50-kW proton exchange membrane (PEM) fuel cell system suitable for providing grid-independent energy sources for large facilities.

in Oman. The joint venture will operate the multi-purpose marine jetties, consisting of seven deepwater berths for vessels up to 100,000 dwt.

Oiltanking of Germany is to take a *shareholding in Star Energy Resources, which owns and operates a 610,000 cm capacity petroleum products and chemicals terminal at Jebel Ali in the United Arab Emirates. The facility is to be rebranded 'Star Energy Oiltanking'.*

Fluor Corporation has signed a mem- *orandum of understanding with a joint venture of Dow Chemical Company and Petrochemical Industries Company to provide utility and infrastructure front-end engineering and overall project management consultancy services for a major petrochemical project in Kuwait.*

ASIA-PACIFIC

Indian Oil Corporation is reported to *have opened its first fuel retailing outlet in Mauritius, at Tere Rouge in Port Louis. The company will be the fifth player in fuel retailing in the Island nation, after Shell, Total, Caltex and Esso. In all, IOC plans to open 25 service stations in Mauritius, which consumes about 1mn t/y of petroleum products.*

AFRICA

The stalled privatisation process of *Nigeria's four refineries will recommence in 1H2005 according to the Bureau for Public Enterprises (BPE). Towards this end, President Olusegun has directed the Nigeria National Petroleum Corporation (NNPC) to pay the privatisation advisers appointed by BPE to help prepare the refineries for public offer, reports* Stella Zenkovich.

WORLD

More than 400 new coal-fired power *plants are in planning and construction in just two countries – China and the US. China will need 60 new 600-MW coal-fired plants per year just to keep up with its soaring electricity demand, according to 'World Power Generation Projects' – an online service provided by the McIlvaine Company. The cost of a 600-MW power plant is over \$700mn. With soaring power demand and rising oil and gas prices, coal-fired plants with an aggregate cost of over \$1tn are in construction or planning worldwide.*

New liquids fuels venture in South Africa

Petronas is reported to have signed a definitive agreement with Sasol, Tshwarisano LFB and Engen to merge into a new liquid fuels joint venture – Uhambo Oil – in South Africa. Uhambo will be the leading South African liquid fuels refining, marketing and distribution business, with a capacity to produce more than 13mn cm/y of petrol, diesel and kerosene.

Uhambo will comprise the Enref oil refinery at Durban, Sasol's share in the Natref crude oil refinery at Sasolburg in the northern Free State and about 1,600 retail service stations in South Africa, as well as liquid fuel operations in 13 other sub-Saharan African countries. It will also include liquid fuels components produced at the blending facility at Secunda from synthetic fuel (synfuel) components. These synfuel components will be procured from Sasol Synfuels.

It is estimated that the joint venture will have a market share of about 33% in South Africa for white petroleum products – mostly gasoline, kerosene, jet fuel and diesel. Uhambo will be looking to sell about 60% of its output directly into its own marketing network and a minimum of 25% to other oil companies, with the remaining volumes initially destined for the export market.

The retail network in South Africa will include more than 1,250 Engen service stations and about 350 Sasol, Exel and Zenex service stations, including Engen Quickshop and Sasol Delight convenience shops.

UKOOA 'disappointment' over UK fuel duty

UKPIA has expressed 'disappointment' that the UK Chancellor, in his pre-Budget statement, has decided not to implement the duty differential for sulphur-free petrol and diesel (less than 10 ppm sulphur). The Chancellor first announced his intention to introduce a lower rate for sulphur-free fuel, in comparison to the current ultra-low sulphur fuels, in his 2002 Budget and this was confirmed in both his 2003 and 2004 Budget statements.

Chris Hunt, Director General of UKPIA, commented: 'Our member companies have been investing substantial sums at refineries in readiness to start producing these new fuels from September 2004, mindful of the government's wish to see them introduced in the UK ahead of the EU mandated timetable of availability on a balanced geographic basis from 1 January 2005 and complete availability by 2009. Introduction of these new fuels requires long lead times and careful planning of production, distribution and storage to ensure a smooth transition with no impact on consumers'.

He concluded: 'Uncertainty over the direction of government policy creates confusion so we look forward to an early decision from the government on how these new fuels should be introduced.'

Energy efficiency linked to bills

British Gas is understood to have become the first utility company to link energy efficiency directly to customer bills, with an offer to freeze prices for three years for households that sign up to a new environmentally friendly tariff, 'Warm Fix'. The company is offering savings of £30/y for customers who switch to the new tariff for their gas and electricity. However, there is a £100 early redemption penalty for customers withdrawing from the scheme within the three-year period.

The new tariff is understood to be 9% higher than BG's standard tariff, which means it will cost a typical customer with a three-bedroomed house £60 more a year in gas and electricity. In return, BG will install energy efficiency measures such as cavity wall or loft installation and low-energy light bulbs for free, which it says will reduce energy bills by an average of £90/y.

The scheme is designed to help the UK government meet its ambitious target of a 20% improvement in energy efficiency by 2010, which will help reduce carbon emissions by as much as 4.2mn t/y.

A new frontier

A change in the way that the LNG shipping business runs has been predicted for a few years. Recent developments suggest that this new model has already taken hold, as Peter Mackay* *explains.*

When energy analysts predicted massive growth in the LNG market a few years ago, the old hands in the LNG business were sceptical that the trade model being proposed would ever come to pass. After all, LNG had always been a project-led trade, with expensive ships moving gas from point-to-point and spending half their time in ballast.

It is rapidly becoming clear, though, that the old LNG model is indeed being overtaken. Continuing growth in energy demand – demand that cannot be met from new or existing oil supplies – and the emergence of new gas liquefaction projects are swiftly generating new LNG trades and a new structure for the LNG shipping industry. It is possible to see the business dividing into two – existing ships continuing to ply traditional trades using the old model; and a new fleet emerging that is responsive to market demands and has the flexibility to switch trades.

Hand in hand with these changes are coming other developments in the LNG shipping market. Whereas ship operation and – to a large extent – ownership was reserved for the major energy companies, large gas consuming utilities and state interests, as well as some of the larger independent shipping companies are now getting involved. As the fleet gets larger, there is a growing need for participation by shipowners with the expertise to handle the operational and manning requirements. A marketplace that is rapidly opening up offers the promise of profits for independent operators.

Demand is the key

Expansion in the LNG trades has been underpinned by two factors – continued growth in energy demand, especially in the US and China; and the high level of crude oil prices, which are expected to persist at historically high levels for the foreseeable future. Access to additional supplies of crude oil is constrained by both political factors and predictions of an imminent peak in global oil output. It is increasingly difficult to see how demand in the US can be met by additional refinery capacity or increased imports of refined products. And booming consumption levels in China are very attractive to gas exporters east of Suez.

By contrast, there are still large untapped reserves of natural gas. They have so far been less widely exploited because of the logistical difficulties of moving gas to market. However, with delivered gas often being priced against crude oil, general expectations of higher oil prices mean that it is feasible to put in place the heavy investment needed to set up liquefaction and regasification facilities and to build additional ships.

Natural gas also has the advantage of being seen as a more environmentally friendly energy source than crude oil or other liquid hydrocarbons. This is a significant selling point as far as the US market is concerned, and it is also a factor in China, where there are concerns that rapid industrialisation will further impact air quality. For both the US and China, however, incremental natural gas supplies will almost all have to arrive in the form of LNG since the potential to expand pipeline supplies is limited.

These factors have already led to a significant increase in global LNG trade. According to Poten and Partners, world trade increased from 100mn tonnes in 2000 to 135mn tonnes last year. Projected trade for 2005 is 161mn tonnes, rising to 224mn tonnes by 2010 and, on current forecasts, 282mn tonnes by 2015.

However, whereas in the past forecasts of LNG trade could be seen as fairly reliable, since most projects relied at one end or both on government support for the exploitation of natural gas resources or the choice of LNG as a means of supplying natural gas, the outlook now is less certain. Much of the projected growth relates to US imports and demand here is heavily market-related, relying on commercial rather than national strategic decisions.

On the one hand, current gas prices at Henry Hub (the marker price for the US) are comfortably above the levels needed to justify construction of new regasification capacity. However, lead times for construction approvals can be lengthy; while the US government has expressed its support for an expansion in LNG imports, virtually all of the 30 or so projects put forward for receiving terminals in the US have been challenged by local interests, mainly on safety grounds. To try and counter this, various interests in the LNG sector have formed lobbies to try and put a positive safety case forward to public groups, politicians and environmental interests.

It is almost inevitable, therefore, that US LNG receiving and regasification capacity will be exported, both to Canada and Mexico. Apart from the expansion of the four existing LNG receiving facilities in the US, additional capacity will come first from sites in eastern Canada, where work is already under way on Anadarko's Bear Head facility. Petro-Canada and TransCanada have another site on the cards at Gros Cacouna in the mouth of the St Lawrence. Both terminals will feed gas into the local Canadian market as well as the north-eastern US.

Bearing in mind the heavy and growing demand for energy in California and other high-growth states in the south-western US, Mexico is also a promising area. Two projects have been approved – the Shell/Sempra Energy Costa Azul facility in Baja California, and the Shell/Total plan in Altamira. While some of the gas imported via these facilities will be used by the local market, which is also hungry for gas, some – particularly from any terminals in Baja California – is very likely to find its way into the US, either through the gas grid or in the form of electricity generated by power plants close to the LNG landing sites.

The Costa Azul project is highly significant, since it will also be the first Pacific-facing import terminal in North America and will probably rely on supplies from new export projects in Australia and Indonesia. New import capacity on the Atlantic and Gulf coasts will find a wider range of potential suppliers, including Trinidad, Nigeria, Algeria, Norway (once Statoil's Snøhvit project comes onstream), Egypt, Equatorial Guinea, Angola and Qatar. Russia is another potential supplier, especially since Gazprom has confirmed that its first LNG export facility is to be built at Ust-Luuga on the Gulf of Finland.

Shipping impact

While the US presents the most exciting new area for LNG business, several other countries are coming to LNG as an economically attractive and strategically secure means of providing new sources of energy. In the case of the UK, where there are three major receiving terminals in various stages of completion, it marks a return to LNG imports. Around the world, however, the growing number of LNG production facilities means that importers can be confident of finding supplies. On the opposite side of the fence, and following the model set by Atlantic LNG in Trinidad, existing projects are now taking to adding trains without having all – or even any – of the new capacity assigned to buyers.

These trends make it more difficult than in the past to forecast vessel demand with any accuracy. The supply/demand forecast is also complicated by the fact that some of the older ships still trading – several are already over 30 years of age – will need to be scrapped at some point. Estimates have varied as to how long these ships can be kept afloat; the nature of LNG means that the containment system does not age, and as long as the hull and machinery are kept in good condition it has always been thought that a lifetime of 40 or even 45 years is not unreasonable.

However, for the first time projections of fleet supply and newbuilding requirements are beginning to factor in a figure for fleet replacement. Mitsui OSK Lines (MOL), one of the largest LNG tanker operators, calculates that this aspect will increase steadily, from six ships this year to 22 in 2010, 40 in 2013 and 48 in 2015, based on a 35-year vessel lifetime.

Meanwhile, the demand for new ships to service new trades will also grow year-on-year. MOL says that 55 incremental new ships will be built this year, 81 next year, 84 in 2007, and that this figure will go on rising to 115 in 2010 and 173 in 2015. By the end of this forecast period, the LNG fleet will have expanded to 311 ships, from a current figure of 166, MOL estimates.

Figures from Drewry Shipping Consultants highlight the immense task of meeting the short-term requirement for new vessels. In November it put the orderbook at 105 ships, amounting to 15.6mn cm capacity – or 80% of the current fleet capacity. Of these 105 ships on order, 64 were contracted last year.

One limiting factor in fleet expansion is the shortage of suitable yard capacity. A relative handful of shipyards have the ability to build LNG tankers and these are now nominally full at least until 2007. Some moves have been made to expand capacity – Daewoo has implemented new systems to try and squeeze out one more ship each year, while Hyundai Heavy Industries is moving some construction activity to its subsidiary Samho. Nevertheless, newbuilding prices are on the rise. *Lloyd's Shipping Economist* reports average prices for a 'standard' 140,000 cm ship of $173mn in September 2004, compared to $150mn a year earlier. Such prices are still well below those of ten years ago, where average quotes were in the region of $240mn per ship and European builders could compete.

French shipbuilder Chantiers de l'Atlantique has acknowledged in effect that European yards cannot play a part in building standard ships (at least, not without subsidy) and have to concentrate on innovation. It is already active in one area, building the first LNG ships with diesel-electric dual-fuel propulsion systems rather than steam turbines. The other significant development waiting in the wings for future LNG ships is an increase in capacity – some projects are already looking at vessels of 200,000 cm, but no firm orders have yet been placed. However, increased size is something that the big Korean and Japanese yards may be best placed to achieve at a reasonable price.

One way or another, the new ships that the LNG business needs are coming. The demand exists, the supply is willing, and the necessary funds are being found. One thing is clear – the new model of the LNG shipping business is already with us.

**Peter Mackay is Editor of* Hazardous Cargo Bulletin, *a monthly magazine that covers the LNG sector.*

A Scandinavian saga

Maria Kielmas *takes a closer look at the use of nuclear power in Scandinavia and Europe, in particular the proposed phase-out in Sweden.*

Marian Radetzki expects to get his champagne and whisky for free in 2005 – just as he did in 2004. The Professor of Economics at Luleå University of Technology and a senior researcher at the Stockholm-based think tank, Centre for Business and Policy Studies, has had a number of running bets with friends and colleagues that successive Swedish governments will never fulfil their enduring promises to phase out nuclear power. Ever since a 1980 referendum voted narrowly in favour of a nuclear-phase out over the following 25 years, only one generating unit at one plant – Barsebäck-1, which is located just north of Malmö – has been closed.

However, in early October 2004 Prime Minister Göran Persson announced suddenly that the second, and remaining, generating unit at Barsebäck will be closed in 2005. Talks between the government and the electricity industry about introducing a nuclear phase-out had stalled so the government was taking the initiative, Persson said. He later stressed that: 'Nuclear power has run out of steam'.

Despite this, Redetzki is still confident of winning his bets – 'I believe that the government will find it very difficult. They will not be able to close it [Barsebäck]. There has been very little new [generating] capacity expansion in Sweden for a very long time.'

Environment Minister Leif Pagrotsky thinks otherwise. Nuclear energy in Sweden – which accounts for half the country's power supply – was developed in just 13 years and could be phased out over a similar period, he believes. Barsebäck-2 has only a limited input into the Nordic electricity market and its closure will not cause any dramatic increase in consumer power prices, he says. Wind energy could be developed on a much larger scale and even gas-fired power plants could be constructed close to Gothenburg, where the gas could be piped in from Danish fields.

Popular support

A television opinion poll in October showed that 64% of the 1,000 individuals canvassed thought Sweden should continue to use nuclear power, 16% thought it should be expanded, and 16% wanted it phased out. Some 71% of voters for the government Social Democrat Party think that nuclear power should remain, while only 13% of them want it phased out. Meanwhile, voters for the Social Democrat's coalition parties – the Greens and the Left Party – thought that nuclear power should be phased out by 54% and 45% respectively. A far broader poll in early October indicated that nearly 82% of the population want nuclear power to stay.

Despite these figures, in the government's view it is the people who are out of step. Marita Ulvskog, Social Democrat Party Secretary said: 'Very few of our voters realise that the Social Democrats have decided to change our energy policy and phase out nuclear power so that it has a minimal impact on jobs and welfare.'

The winner in this policy will be wind power, which in 2004 supplied 3.5% of the country's electricity, or 5 TWh (tera watt hours). The government's goal is to double this amount as soon as possible. Thomas Korsfeldt, the Director of the Swedish Energy Agency, a government entity, said in October that wind power's stock is rising in the country and is on an equal footing with other interests such as defence and the environment for designated areas. Spokesmen for armed forces throughout the European Union have warned that offshore and onshore wind farms could impede defence communications. In Sweden, proposals to site wind farms in picturesque regions such as Dalarna and Norbotten have met strong resistance on both defence and environmental grounds. So, why is the government fixed on such a confrontational path?

Political circus

This has been the style of Swedish energy policy over the last 30 years, says Marian Radetzki. The government has presented itself as wiser than the markets or the energy industry, and as a champion of securing a long-term energy supply at a low cost. But the reality has been a short-term circus of incompetence and corruption, which has resulted in greater costs to consumers, greater losses to the environment, and at least a 0.1% lower GDP each year over the period. He estimates that this amounts to approximately 100bn krone ($15bn) over the 30-year period.

The governing Social Democrat Party's latest flip on nuclear power coincides with a remark made by Lars Ohly, the leader of the Left Party. Ohly said he still considered himself a communist. Up to the fall of the Berlin Wall the Swedish Left Party was generally considered as communist. But since that time it has made great efforts to present itself as democratic. Ohly's remarks drew unwelcome attention to his party's close links with the governing communist parties in the then Soviet bloc. Prime Minister Persson was prompted to remark that Ohly, like nuclear power, 'had run out of steam'. The Social Democrats now hope to consolidate their coalition with just the Green Party, with an eye to next year's general elections. Part of the Green Party's price appears to be the faster phase-out of nuclear power.

New Finnish plant

Sweden's latest attempt to dump nuclear comes at the same time as Finland begins construction on its fifth nuclear plant – the 1,600-MW Olkiluto-3 at a location of the same name just north of the historic city of Rauma on the Baltic Sea coast. This expansion of nuclear capacity, some 19% of total energy supply in Finland, has received broad support in the country. Finland's principal export earner, the pulp and paper industry, requires ample supplies of electricity at economic prices while no government has wanted to increase gas imports from Russia, the only energy alternative. (Finland lost half of its territory to the Soviet Union after the Second World War.)

If Sweden goes ahead with its nuclear phase-out, Finnish officials speculate that there could be a greater opportunity for sales of Finnish nuclear power to Sweden via a proposed electricity link across the Baltic Sea. This has even led to the notion that Finland might be able to build a sixth nuclear plant in the near future. So, Sweden faces replacing its own nuclear power with nuclear power from Finland, coal-fired electricity from Poland, or coal and nuclear electricity from Germany.

But Germany also plans to phase out nuclear power by 2021. This situation dates from when the Social Democrat and Green coalition government came to power in 1998. The 2002 Atomic Energy Act stipulates that the last nuclear power plant should be shut down by 2021. However, unlike Sweden, the shut-down programme will not be dictated by government – just its deadline. German power suppliers are required to decrease the percentage of nuclear in the national energy mix until the required deadline. Marian Radetzki thinks that even if the Barsebäck-2 facility is not closed down in 2005, the Swedish government will eventually adopt a nuclear phase-out scheme similar to Germany's. Whether this will be carried through is another matter.

No alternative

Early November opinion polls in Germany indicated that over 80% of the population is opposed to the nuclear energy phase-out. But these results only prompted the government to reassert its phase-out plans. The hard-line anti-nuclear Environment Minister Jürgen Trittin re-confirmed this on the Ministry's website.

Last year, even Belgium followed the nuclear trend. In a country where over 60% of electricity comes from nuclear power, legislators voted by two to one to phase-out nuclear by 2025. Anti-nuclear groups in western Europe are pushing for the greater use of wind and other renewable energies. Meanwhile, in eastern Europe the replacement of nuclear power is not going to be as straightforward as previously thought. Slovakia, Bulgaria and Lithuania agreed prior to their accession to the EU that they would close down nuclear power plants dating from the Soviet era which the EU deemed as unsafe. But with no alternate energy supplies, in October all three governments filed requests with the European Commission for extensions to the lifetimes of the affected plants.

Although British energy experts widely believe that the country will need new nuclear capacity as North Sea gas supplies fall off, the government so far has made no outright statement on the matter. No new nuclear policy statement is expected until at least a year after the next UK general election. Only France, who obtains 50% of its power from nuclear, remains overtly in favour of the fuel. Finance Minister Nicholas Sarkozy, who is expected to stand for the presidency in 2007, said in October that nuclear is the answer to high oil prices. Even some advocates in the environmental movement are proposing new nuclear plants as a way of cutting back on greenhouse gas emissions.

Waste disposal

After nearly 60 years of civil and military use of nuclear energy, a decision on how to dispose of the waste products it generates – in particular the highly contaminated variety such as spent fuel rods – is something few governments and scientists really want to take. 'The big issue is whether people will ever be willing to put something at the bottom of a hole in the ground for tens of thousands of years – even if you could prove the technology to be beyond reasonable doubt. It still smacks of passing things on to the next generation,' comments Steve Kidd, Strategy and Research Manager at the London-based World Nuclear Association.

To date, only Finland has decided on the location of a final repository – to be built next to the Olkiluoto plant at a cost of some 1bn (compared with the plant's original cost of 3bn). According to the current Finnish plans, the spent fuel will be placed in canisters of nodular cast iron. This, in turn, will be surrounded by an external copper canister of about five centimetres thickness. These canisters will be lowered into tunnels drilled at 800 metres depth in the Precambrian gneiss of the Fennoscandian Shield. There will be multiple safety barriers in the repository and the canisters themselves will be surrounded by bentonite clay. This will act as a buffer against any earth movements and will swell up when it comes into contact with water, thus ensuring radionucleides in the canister will not come into contact with the surrounding environment. Work on the disposal site is scheduled to begin in 2009 and the site itself will come into operation in 2020.

Sweden has adopted a disposal methodology similar to Finland for two possible high-level waste repositories in Östhammar and Oskarshamm, about 135 km south of Stockholm. Local communities at all of the Scandinavian sites broadly support their location. But this is not the case in Germany, where public demonstrations against nuclear waste disposal are a regular occurrence. In early November, a demonstrator was killed accidentally when protesting against the transport of French nuclear waste by rail to an intermediate site at Gorleben in Lower Saxony. Gorleben is also the site for a high-level waste repository. The German solution is to pack the waste into stainless steel canisters and bury these in a salt dome. But there are widespread doubts that any decision on its development will be taken before 2030, some 15 years after nuclear power is supposed to have been phased out in the country. This means that no final repository could be ready in Germany before 2050.

Growing problem

Matters are no better in the UK. In November the Committee on Radioactive Waste Management (CoRWM), which advises the Scottish Executive, reported that waste from the UK's nuclear programme is at least nine times higher than previously estimated. A massive 18mn cm of soil and rubble is now known to have been contaminated by leaks and spills at 30 nuclear sites across the country over the past 60 years. This figure could double to 36mn cm when the full extent of the problem is revealed. And this is only low-level waste. Although some five sites have been identified as possible end repositories for high-level waste, there has been no investigative work on any of them.

The US situation is even worse. Over the past 25 years the Department of Energy has spent $6.5bn on work at the proposed Yucca Mountain, Nevada, high-level waste repository. Here, the idea is to pack high-level waste into stainless steel canisters, themselves surrounded by titanium. These would be buried at depths of some 500 metres in a 12mn year-old welded tuff (the geological term for solidified molten volcanic ash) whose porosity varies between 10% and 30%. This has not inspired confidence in the local population and among scientists alike.

In July 2004 a federal appeals court ruled that to use the site, the government – ie the Department of Energy – would have to show that it would be able to hold waste for hundreds of thousands of years. This ruling effectively throws the question back to Congress. In the 1980s it was Congress, not scientists, who chose the Yucca Mountain site in the first place. In the meantime, the US has about 60 so-called 'temporary' nuclear waste storage facilities, some of which date back as far as the Manhattan Project which developed the atomic bomb in the 1940s.

Surveys both in Europe and North America have indicated that nuclear waste management is the primary popular concern with nuclear power. So, whether governments decide to prolong nuclear power plants beyond their initial lifeline, phase them out earlier, or build new ones, the issue has become an irrelevant short-term political fix. Tackling the waste issue is a growing problem that most nuclear nations do not want to touch.

Where are we going?

Richard Baker provides personal comment on the regulations covering the transport of dangerous goods in the UK. He argues that although a European Directive calls for such legislation to be harmonised across the European Union, a range of exemptions in the UK has led to confusion, unsafe practices and unfair competition.*

Legislation covering the transport of dangerous goods by road in the UK has been with us for many years. Following a disastrous camp-site incident in Spain – in which 180 people died from a fuel fire after a tanker split because it had been carrying loads which caused weaknesses in the structure that led to failure in the heat – the 1981 Tanker Regulations were launched prematurely in the UK, closely followed by the packaging regulations. These two sets of legislation were later to become combined as originally planned and now, with the harmonisation process, the latest legislation – the Carriage of Dangerous Goods and Use of Transportable Pressure Equipment Regulations 2004 – came into force in May this year.

However, although seeking to comply with the EU Directive on harmonisation throughout Europe, the UK has meddled with what was perfectly acceptable legislation from Brussels. In doing so, it has rendered the legislation incomprehensible and unworkable. If the UK version of the CDG (ADR) regulations is studied it will be found that some cross references lead nowhere, while others send you round in circles. Furthermore, some of the UK amendments contradict the EU part of the legislation. For example, try finding the definition of mobile plant and the labelling regulations refer to the placarding in ADR but then there are exemptions that further remove parts of ADR.

Profound implications

The implications for the industry are profound. Those who seek to follow best practice are going to be penalised because the UK government has seen fit to issue some 20 exemptions in just five months, bowing to pressure from an industry that has had ample warning of the pending legislation. Such exemptions include the removal in the UK of the ADR requirement for reflective panels on the back of a vehicle. Also, the transport of diesel at temperatures above 100°C, which has been on the cards for years, now sports an exemption from driver training – further evidence of the UK's reluctance to move forward in the field of the transport of dangerous goods and therefore keeping behind Europe.

In my opinion, any exemptions are entirely due to general inefficiency and the trade association's lack of readiness. More worryingly, they will compromise public safety and the safety of emergency responders.

European example

The majority of European hauliers leave most UK companies standing when it comes to compliance and standards. This means that if a vehicle from the continent is involved in an inci-

Industries and trade associations' lack of understanding of rationale behind the legislation puts people at risk

Fire extinguishers are important – unfortunately, the state of this one is not uncommon on UK vehicles

Why do we issue an exemption notice on something that improves safety? – UK vehicles do not need to display reflective panels at the rear of the vehicle

dent, the emergency services are likely to be able to respond appropriately and disruption minimised.

However, shamefully, if the vehicle is based in the UK the chances are that 'exemptions' will mean that, legally, the emergency services are often working in the dark. The outcome could mean that roads are closed for an unnecessarily long time, or an area could be evacuated on a false assumption, or emergency responders could be put at risk because a product was not clearly identified.

A number of UK hauliers are complying fully with the regulations – at least as far as their best understanding of the UK version of the legislation allows them to. Unfortunately, these firms will be at a distinct pricing disadvantage, which is unjust as well as unsafe. All this because the government does not have the courage to tell the industry: 'Comply or cease trading'.

The UK guessing game

A brutal fact

The EU legislation was intended to harmonise requirements for the transport of dangerous goods by road, creating a level playing field for all. However, the UK has added to and amended the regulations, and those in this country who seek to comply fully are asked for more than our European colleagues. Furthermore, those who have the 'muscle' to demand exemptions are cheating the public and the industry. ●

Not exactly a professional approach to labelling

** Richard Baker is currently Chief Fire Officer of Knight Support Fire, Rescue and Ambulance Services in Dar es Salaam, Tanzania. Before this, he spent 25 years with the UK emergency services and was co-author of the* Institute of Petroleum Tanker Emergency Tanker Recovery Code of Practice. *For over five years he also ran the UK Consultative Officers Course for police officers with Kent County Constabulary and was an outspoken critic of the removal of enforcement powers in the 1980s. Author of the* Guide to ADR *and the* Police Blue Book for the Transportation of Dangerous Good, *Richard is still active in on-the-road enforcement.*

No short-term fix for US oil and gas

Despite its electoral success, the new Republican government has few options regarding what it can do to bring about changes in the US energy scene. There is effectively no way it can appreciably increase domestic output of oil and natural gas in the short term, and even small moves in this direction face an assortment of barriers. Judith Gurney *reports.*

Production of oil and gas within the US is stretched to its limits, as the volatility of oil and gas prices so clearly illustrates. Problems at refineries, and even rumours that these may occur, can send oil prices surging. The ravages of Hurricane Ivan in mid-September 2004 in the Gulf of Mexico – a significant source of US oil and gas output – resulted in a dramatic and lasting effect on the prices.

Although Ivan did some damage to offshore production facilities, including the wrecking of seven fixed platforms and the mangling of four others, the storm's most serious damage was to pipelines that feed a cluster of terminals and refineries located on the tip of Louisiana. About one third of the Gulf's 33,000 miles of pipelines were in the hurricane's direct path, many of these in mud off the mouth of the Mississippi river. Ivan's force, both incoming and receding, triggered a multitude of mudslides – dramatically damaging pipelines. Locating and repairing these lines, some buried by as much as 20–30 ft of mud, was slow work. A week after Ivan, 34% of daily normal Gulf of Mexico oil production and 20% of daily normal gas production was shut in. Two months later, some 12.5% of daily oil production and 6.03% of daily gas production was still shut in. (These percentages did not include production lost due to damaged or lost platforms.)

Financial restrictions

Another factor limiting what the new government can do is the huge current deficit it has inherited, stemming partly from costs in Iraq but also from the effect on federal revenues of tax reductions.

The omnibus energy bill presented by President Bush at the beginning of his first term in office, which Congress refused to pass, had a price tag of nearly $100bn spread over a few years. Consideration of an expenditure of this magnitude is no longer feasible.

Aggressive state governments

Another restriction comes from the power of individual state governments to enact legislation or promulgate regulations that contradict the positions of the federal government. Lengthy court proceedings resulting from these state initiatives can postpone or even prevent the imposition of federal guidelines. In 2003, for instance, the administration pronounced that the federal government had no authority to limit carbon dioxide and other global-warming gases unless Congress specifically gave it that power. This led to unresolved lawsuits filed by several state attorney generals and environmental groups.

Another example is the demand by California state regulators for a dramatic improvement in fuel economy requirements – the average number of miles per gallon of gasoline in vehicles sold in the state – to a level well in excess of that required by the federal government. Yet another is the approval by Colorado voters in November 2004 of ballot measures that require utilities to obtain at least 10% of the electricity they supply to the state's consumers from renewable resources by 2015 – a requirement once again far in excess of federal regulations.

1999	0.22
2000	0.22
2001	0.22
2002	0.23
2003	0.51
2004*	0.69
2010*	2.16
2015*	3.11
2020*	4.14
2025*	4.80

**estimate*

Source: US Energy Information Agency

Table 1: US LNG imports, 1999–2025 (in tn cf/y)

Arcane Senate rules

Despite increased Republican control of Congress, the administration cannot count on securing the passage of legislation dealing with energy issues. The Senate's rule allowing unlimited 'filibuster' debate during the consideration of a proposed bill can effectively delay or prevent the passage of measures supported by a majority of senators. This was the main tactic used to defeat the energy bill in the last Congress. Although the Republicans have a clear majority in the new Senate, they will have difficulty attracting the two-thirds majority vote required to bring filibusters to a close.

Filibustering can be circumvented by tacking a specific item concerning energy onto a bill dealing with budget reconciliation, as was done regarding support for the Alaskan pipeline last autumn. By Senate rules, opponents cannot filibuster a budget item. For inclusion in a fiscal bill, however, an item must be shown to eventually generate income for the government.

There are, however, a few changes which seem possible and, in some cases, probable.

Alaska gas pipeline

Prospects for the construction of a pipeline to bring Alaska's North Slope gas to markets in the US Midwest are brighter. Last autumn, Congress passed fiscal legislation which contained riders giving substantial tax benefits, loan guarantees, assurances of expedited permit approval systems and other incentives for the construction and operation of a gas pipeline running along a route roughly parallel to the existing TransAlaska oil pipeline. These measures had originally been included in the failed omnibus energy bill.

What ExxonMobil, together with BP and ConocoPhillips, the partners involved in the pipeline project had demanded, and what Congress failed to give them, was a guarantee of subsidies if gas prices fell below a given floor price during construction and subsequently. This form of price insurance is unlikely to see the light of day in the new government as President Bush insists that subsidies, promised as well as actual, would distort the natural gas market.

The government of Alaska is substantially increasing the odds for the construction of a pipeline capable of delivering 4.5bn cf/d to the Lower 48 states. Alaska, whose economy is feeling the effects of the continued fall in domestic oil production, is trying to arrange a deal with the pipeline partners whose terms would involve the state investing billions for a stake in the venture, some say perhaps as much as 25% of its cost. In return, the state would be entitled to royalties on natural gas production as well as taxes on the proceeds of the project. For their part, the partners would shoulder a lower share of risk and would probably have better terms on taxes and environmental requirements. The Alaskan legislature is scheduled to consider this deal early in the new year.

There are still other issues which need to be settled before the project partners have enough confidence to invest money in seeking environmental permits and drawing up detailed pipeline work, and these can take time. They need to settle Canadian rights of way as the proposed pipeline will pass through Canada, as well as the rights of any indigenous tribes involved along its route. Negotiating with the Canadian authorities will be easier now that the Canadian MacKenzie Delta project designed to bring gas and natural gas liquids to Canadian and US markets is no longer viewed as being in competition with the proposed US pipeline. This project also seems to be closer to realisation although regulatory issues still need to be settled.

It is also safe to assume that exploration and production will increase in the Rocky Mountains, especially in the Powder River Basin in eastern Wyoming and south-east Montana, and in the Green River Valley in Wyoming.

The administration can be expected to further relax and expedite permit procedures to allow more extraction of gas, coalbed methane, and possibly oil. It can do this with executive orders and without Congressional action.

Refining and LNG

It is estimated that 30% of the 150 or so US refineries haven't upgraded their plants to allow them to run oil that is heavier and higher in sulphur – and cheaper. The new administration is expected to take measures to encourage upgrading. In addition, it will try to make it easier for the construction of new refineries by relaxing regulatory restrictions. No new refineries have been built in the US for 28 years. Once again, regulatory changes can largely be achieved through executive orders without recourse to Congress

Meanwhile, although the administration can make it easier for companies proposing new LNG terminals by relaxing the permits which emanate from the federal government, most of the opposition to new terminals comes from state and environmental groups. It is conceivable that the administration will be able to negotiate compromises with some of these groups by offering concessions in others areas of their concern.

Barring a major LNG accident, it seems safe to expect that plans for several new LNG terminals will go ahead in the coming year. The projects with the best chances for a successful outcome are offshore and onshore terminals in the Gulf of Mexico, even though gas pipeline capacity from the Gulf area to mid-west and north-east home-heating and electricity markets is limited. New terminals nearer these markets, like the recent proposal by Shell and Transcanada for a floating LNG terminal off the coast of Long Island, have less chance of seeing the light of day due to local opposition.

From	2003	Jan–Aug 2004
Opec		
Saudi Arabia	1,726	1,463
Venezuela	1,183	1,317
Nigeria	832	1,094
Iraq	481	665
Kuwait	208	227
Algeria	112	230
Other Opec	36	36*
Total Opec	**4,578**	**5,032***
Non-Opec		
Canada	1,549	1,602
Mexico	1,569	1,594
Angola	363	303
UK	359	249
Norway	181	174
Colombia	166	147
Russia	151	127
Ecuador	139	208
Gabon	131	128
Trinidad & Tobago	67	67*
Other non-Opec	412	259*
Total non-Opec	**5,087**	**4,858***
Total imports	**9,665**	**9,890***

**estimates:* *Sources: US DOE Energy Information Agency,* Oil & Gas Journal

Table 2: Average US crude oil imports (in 1,000 b/d)

Nuclear power and global warming

President Bush and the Republican party have repeatedly stated their intention to encourage the development of a new general of smaller and safer nuclear power plants in the US. Making this happen will require Congressional action.

Meanwhile, it is safe to assume that the new Republican government will continue to block the Kyoto treaty and to criticise assertions of global warming. It will not mandate greenhouse gas emission cuts by power plants but will rely on their voluntary efforts. On the other hand, it will probably try to reduce sulphur-dioxide and nitrogen-oxide emissions, probably by resurrecting the Clean Skies Initiative bill which failed to pass in the last Congress.

Exploration activity

Although the federal government would like to see increased activity in the Gulf of Mexico (except in areas off the coasts of Florida and California) its powers to do so are limited to offers of better royalty conditions. Development of discoveries already made in the Gulf will go ahead as planned, but a surge of new exploration seems unlikely. The oil companies which dominate the risky deepwater and ultra deepwater areas of the Gulf apparently are not planning to invest the substantial profits they have made from high oil and gas prices in new exploration, although they intend to increase investment in ongoing developments.

Republicans have repeatedly emphasised that they view the opening of the Alaskan Arctic National Wildlife Refuge (ANWR) for exploration and production as a priority issue. Senator Domenici, Chairman of the Senate Energy Committee, announced shortly after the elections that he planned to insert a measure to this effect early in the new year in a budget reconciliation measure which, as noted earlier, is a method of circumventing the effectiveness of filibuster attempts by minority opponents to defeat it. There are, however, strong environmental and other pressure groups determined to prevent the opening of ANWR and it is said that these include some Republicans. How this fight will end is anybody's guess, but the chances are it will occur soon.

Photo courtesy of 3i

Challenge and opportunity

The North Sea, although a maturing province, still offers a number of E&P opportunities. **Graeme Sword**, *3i's Oil and Gas Director, takes a closer look at some of the challenges that lie ahead.*

The North Sea has arrived at a challenging stage in its development. Exploration activity declined over the past decade and production has been falling from its peak in 1999. At the same time competition for investment is intensifying, with super majors such as BP and Shell channelling more of their exploration budgets away from the North Sea to newer discoveries in the Gulf of Mexico, Brazil and West Africa.

However, the North Sea remains one of the world's great energy provinces – despite creeping maturity. In the UK, the Department of Trade and Industry estimates that some 30bn boe have been produced, with a remaining reserves base in the range of 22–31bn boe – of which around half has yet to be found. Norway estimates that only 40% of its oil has been produced and that remaining reserves are 85bn boe. Both countries' governments recognise the need to develop effective strategies and solutions to extend the productive lifespan of the province.

The past six years have witnessed massive restructuring in the industry, with a string of consolidations among oil majors and minors. With the super majors continuing to squeeze their suppliers on price, the oil and gas service companies are left seeking new opportunities for growth. For service companies in the North Sea, the key challenge is how to market their service expertise on a global stage. Service companies could also gain from the emergence of a strong independent sector, providing they can address the needs of the smaller oil producing business.

Need for technological innovation

Technology is critical to the long-term future of the North Sea and the prize is considerable given the scope to boost recovery rates from mature and marginal fields. The onus on developing and driving new technologies into the marketplace will remain with the operators, large service companies and governments. However, with the super majors now focusing their finances elsewhere, the larger share of that responsibility will fall on the state. It is time for the governments to step up their interest in funding new technology, or face the prospect of the North Sea losing its position as a world leader in the hydrocarbons industry.

Certainly, technical innovation requires a robust and inventive contracting and service/supply sector and we are witnessing the emergence of a cluster of companies that are leading this drive. The challenge is not just to sustain but also to grow this side of Europe's upstream energy sector.

New business models

Increasingly, venture capital and private equity companies are being called on to fund new technologies – but technical innovation needs to be matched by new business models. The emergence of a strong independent sector in the North Sea would help bring new ideas and energy to the challenge of exploiting maturing assets.

The industry needs to consider new investment models and, in doing so, has to create the right conditions to incubate independent businesses that can hold their own with the North American super independents.

One such model, which provides a real alternative to asset divestment, and in which 3i has invested, has been developed by Energy Development Partners (EDP). The company aims to partner with existing asset owners and take technical control of projects without owning the asset directly. The EDP business model creates value by investing technical expertise and capital to increase the producing life of brownfield, fallow and stranded assets. In return, EDP receives a share of the incremental value achieved as a result of extended production. The strategy avoids many of the typical barriers to entry faced by new companies, such as setting aside capital for decommissioning liabilities and winning ownership of assets in auctions.

3i recently played a central role in the buy-out of Swiss-Swedish engineering group ABB's upstream oil and gas manufacturing engineering and contracting business. Once completed the deal will create Vetco International, which, at $924mn, marks the largest ever transaction of its kind in the European service sector.

This buy-out model, which is relatively new to the market, shows how private equity can unlock value in the North Sea. Vetco International's innovative technology and services, coupled with the opportunity to nurture a more entrepreneurial and aggressive sales channel, represented a chance to take a very good business and make it better. One of the benefits of the new buy-out model is that the company already has a highly experienced and motivated management team.

Sustaining North Sea oil

It is in the interests of the UK and Norwegian governments to actively promote increased North Sea exploration and production. The prospect of reduced tax receipts and rising dependence on hydrocarbon imports in the UK have resulted in new policies to encourage the entry of independents that are staking their future on improving production. The North Sea continues to offer very attractive opportunities for investment. This is reinforced by a recent new ventures survey of 200 oil and gas companies by the geophysical company Robertson Research, which places the UKCS as the top destination for investment.

However, the emergence of a substantial and internationally competitive independent sector remains some way off. In both exploration and production (E&P) and services, the industry landscape is starkly polarised between a handful of super independents and myriad small ones.

Economies of scale suggest investors need to be working together to create a smaller number of medium-to-large independents with the scale to make a real impact in the North Sea.

Private equity and venture capital

There are excellent business opportunities for private equity (PE) specialists in the North Sea – perhaps explaining why PE investment in Europe' s oil and gas sector jumped by 127% from 2002 to 2003, at a time when total PE investment in business over the same period fell by 20%.

The restructuring of North Sea oil and gas is creating exciting investment opportunities as well as tough challenges. Independents and small service companies can play a key role in reinvigorating the province, but only if we create the right conditions for them to thrive. Private equity plays a crucial role in this, from seeding innovative new businesses, to helping established players create value and achieve their full potential for growth.

Independents' day?

Innovation is the key to the oil industry's future. Demand for oil continues to rise, and it will become increasingly difficult and costly to replenish supply.

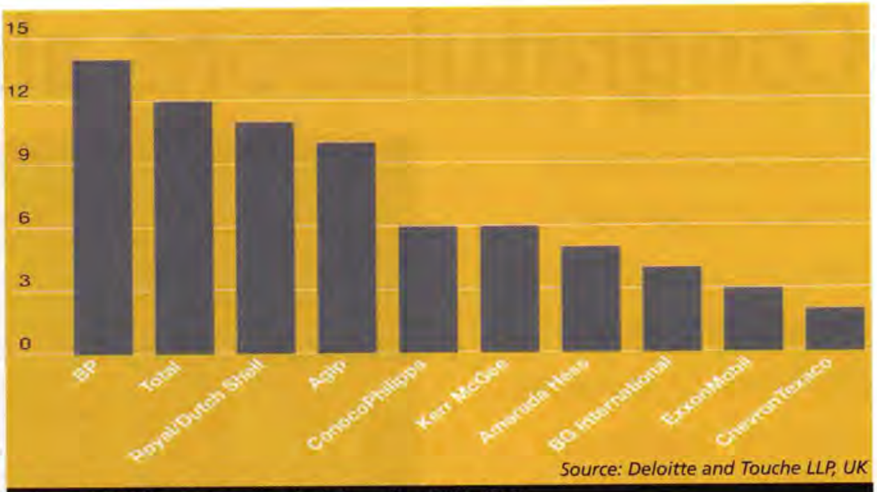


Figure 1: UK North Sea asset deals by seller, 1998–2003

In the long run, finding new ways to prolong production has become as important as making the next big strike, but it's a task of secondary interest to most super majors. The economics of the industry suggest they should focus on giant new discoveries and those assets that yield the biggest returns.

This is good news for those focusing on the enhanced recovery of oil. As the giants divest themselves of marginal properties there are real opportunities for independent E&P companies to emerge. However, the competition for them will remain fierce and margins will be squeezed unless new technologies and new business models can transform the economics of ageing fields.

Adequate funding, first class management and an unflinching focus on growth will ultimately determine the scale of opportunity for the North Sea's independents. Also important is ensuring that the oil companies are underpinned by a robust service/supply sector, where innovation can thrive and the solutions required by oil companies can be developed and then offered for sensible reward.

The creation of a new industry composed of growing and sustainable companies cannot be based only on the hopes for future technology innovation. Great companies have to be focused now on value creation, revenues and returns. Improved oil recovery in tail-end production has as much to do with a company's business model and investment criteria as with technology.

Private equity will be a critical source of both financing and knowledge in this regard, offering access to business networks, industry expertise and the experience of value creation.

The North Sea has the corporates, entrepreneurs and governments all wanting to stimulate activity. Our challenge is to be the catalyst that brings these disparate groups together.

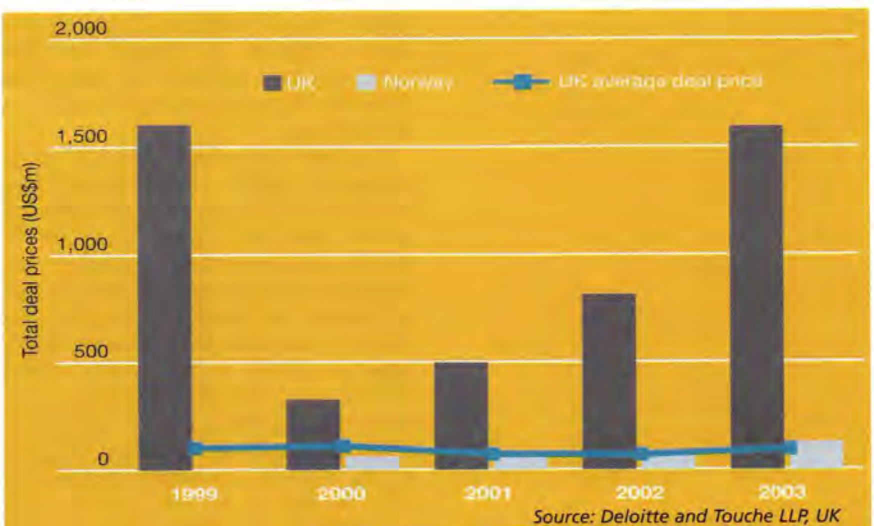


Figure 2: Value of oil and gas deals in the UK and Norway (Statistics are based on sales with publicly released prices. The Norwegian figures exclude the sale of the Norwegian state's interest in upstream activities. The total sales price was identified at $2.1bn.)

Congratulations all round

A host of key industry executives gathered at London's Savoy Hotel for the annual EI Awards Dinner on 22 November 2004. The Awards are the Energy Institute's recognition for excellence and innovation in the world of oil and gas. They also offer both major and smaller companies the opportunity to showcase their groundbreaking initiatives in the international arena.

EI Awards 2004 speaker and presenter Matthew Pinsent CBE

The Energy Institute received some 100 entries for the eight Award categories – Communication, Community Initiative, Environment, Innovation, Outstanding Individual Achievement, Safety, Technology and International Platinum. Judging for each category is based on the achievements deemed to have had the most impact or potential impact on the industry.

Matthew Pinsent CBE, the EI's guest of honour at the Awards dinner, in a humorous and well received opening speech, gave participants some insight into the dedication and application necessary to be an Olympic athlete. He also explained the need for the rigorous training schedules that gave the extra edge necessary to be a gold medal winner. He noted that Awards such as the EI Awards also required exceptional dedication and hard work on the part of the winners. He further noted that this applied not just to those he was presenting the Awards to, but also to all those involved in the achievement. In the course of his athletics career Matthew Pinsent has, in fact, won four Olympic gold medals. A short video of the most recent of these – at the Millennium Olympic games in Athens – was shown, in which in the final of the men's coxless four the gold was won virtually on the finishing line. A race that was so close and so exciting that all at the function were on the edge of their seats just watching the video.

Innovation and excellence

After the Awards ceremony, the Energy Institute's Chief Executive, Louise Kingham, said: 'I am delighted for all involved that this year's Awards have been the best yet on several counts. This was the first year of actively encouraging entries from across the industry, reflected in the depth and breadth of nominations as well as the winning projects. The EI has a responsibility to promote better understanding of the industry and its accomplishments and, I believe, the Awards not only do this but also rightfully acknowledge the talented people creating these achievements.'

The Welcome Reception was sponsored by Wood Mackenzie.

communication

Sponsored by: ABN-Amro

Winner: IT Power – 'Enthuse'

The 'Enthuse' project provides relevant and easily accessible information regarding renewable energy through presentations and workshops, which enables local authorities to be more effective in implementing and encouraging renewable energy schemes. As well as offering ideas and examples of how local government can encourage renewable energy developments, there are also opportunities for networking and the exchange of information.

A format has been developed which includes the 'Renewable Energy Matrix', an interactive tool that helps attendees to identify the way forward for their local authority. The 'Enthuse Toolkit' – an information pack developed to support the initiative – includes leaflets on policies, planning and projects, together with example case studies.

Over 1,100 local authority representatives have participated in 30 Enthuse events held as part of the project to date and the feedback is reported to have been overwhelmingly positive.

community initiative

Sponsored by: BG Group

Winner: npower Health – 'Health through warmth'

The 'Health through warmth' initiative aims to help tackle the issue of fuel poverty, associated cold-related illnesses and winter deaths. It targets and assists vulnerable people to improve their health and living conditions, with energy efficiency and heating measures installed where they are most needed. This ensures that people who are ineligible for other assistance can get much needed support.

The scheme was set up by npower in 2000, in partnership with National Energy Action (NEA), the NHS and other local interests.

environment

Sponsored by: KPMG

Winner: Walsh Ecuador – 'Reducing the footprint of 3D seismic in the tropical rainforest of Ecuador'

Multiple seismic exploration programmes have been conducted in the Ecuadorian Amazon without reusing areas previously cleared for heliports,

Sponsor John Martin, ABN Amro presents Anthony Derrick, Managing Director, IT Power with the Communication Award

Phil Kear, npower, receives the Community Initiative Award from sponsor Peter Dranfield, Vice President, BG Group

Left to right: David Sanchez, Walsh Ecuador; Fernando L. Benalcazar, EnCana; Francisco Silva, Walsh Ecuador; and Dave Westlund, EnCana, with their Environment Award

Richard Olsen, Chair of Production Division, ExxonMobil International, presents Mike Vinzant, Product Manager, Well Completions, Halliburton, with the Innovation Award

Dr Wolfgang Schollnberger (left) receives the Outstanding Individual Achievement Award from John Glesinger, Director, Energy Practice, Norman Broadbent

Sponsor Greg Hill, Production Director, Shell Exploration and Production, presents Nicole McMahon, Director, Policy and Corporate Affairs, BG, with the Safety Award

resulting in unnecessary damage to forests. Walsh Ecuador and EnCana have developed a remote sensing technique to accurately identify historic heliports in mature tropical rainforest, for reuse in 3D seismic exploration surveys.

The Walsh GIS team analysed satellite images from the 1980s and 1990s for historic heliports which had reforested naturally. A total of 324 locations were identified, representing about three times the required heliports for the programme.

Walsh is encouraging EnCana and other operators to apply this technique to seismic programmes in sensitive tropical environments in Ecuador and other parts of the world.

innovation

Sponsored by: ExxonMobil

Winner: Halliburton Energy Services – 'Halliburton DepthStar™ tubing retrieval subsurface safety valve'

The DepthStar tubing-retrievable safety valve (TRSV) is a revolutionary new development in well completion equipment, providing step-change improvements in reliability, safety and cost of overall offshore infrastructure and valve placement.

With operators moving into deeper water, Halliburton found a need to develop a TRSV capable of operating at greater hydrostatic pressures. The DepthStar TRSV was specifically designed to address the inherent challenges of deepwater well completions, while setting a new standard for service reliability. It is claimed to be the first SCSSV that specifically eliminates the potential for well fluids inside the production tubing from migrating into the TRSV actuation and hydraulic control system.

outstanding individual achievement

Sponsored by: Norman Broadbent

Winner: Dr Wolfgang Schollnberger

Dr Wolfgang Schollnberger is a visionary leader, an effective ambassador for the energy industry, a tireless innovator and a prolific oil and gas explorer. His lifetime professional accomplishments have been felt in over 50 countries.

His career began at Royal Dutch/Shell in 1972. He moved to Amoco in 1979, where he served as a Senior Geologist. He later became Amoco's Vice President for Exploration, Africa and Middle Eastern Region. He was also Amoco's Vice President for Worldwide Upstream New Ventures. As Amoco's Vice President of Research and Vice President for Exploration and Production Technology, he oversaw numerous innovations. He served as Chairman of the International Association of Oil and Gas Producers (OGP) Management Committee from 1999 to 2003. He has also been active in the American Association of Petroleum Geologists (AAPG). He recently retired as Technology Vice President for BP.

Not opting for a life of leisure, he is continuing to strive to find options for a sustainable energy mix – for consumers and markets around the world.

As well as benefiting his profession, he has generously given his time and resources to humanitarian causes in Europe, Africa and America. He has also been helping to set up an EI Branch in Houston.

safety

Sponsored by: Shell

Winner: BG Exploration and Production India – 'Investing for a safer future'

BG launched 'Zero LTIF' (lost time injury frequency) in 2003, a behaviour based safety project designed to cut the number of hours lost through workplace injuries.

BG Exploration and Production India, founded in 2002, was the first business in the BG Group to implement the LTIF safety procedures and has set the standard for other operations around the world to emulate. Of the 2.8mn man-hours worked between 1 January 2003 and 31 May 2004, not one hour was lost through lost time injury at the company.

technology

Sponsored by: Eni

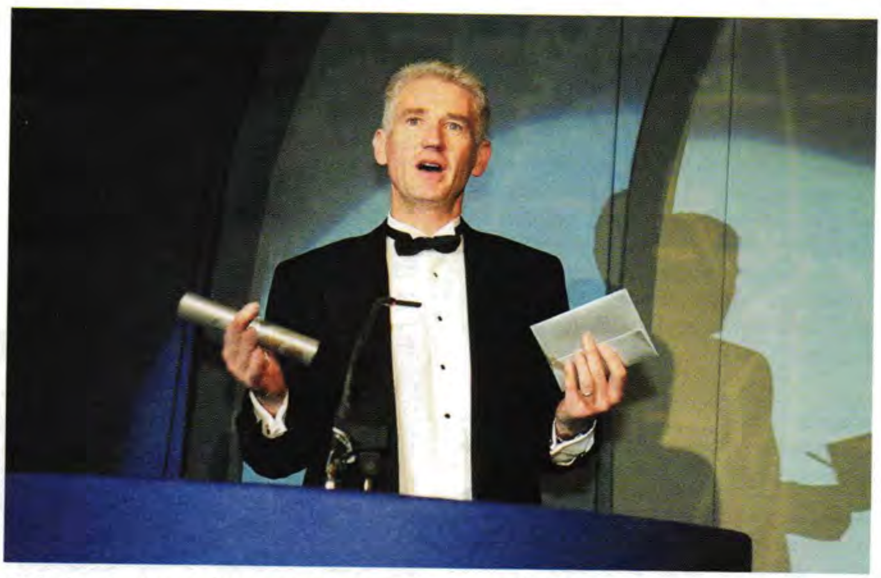
Winner: Shell UK – 'Deployment of high horsepower ESPs to extend Brent field life'

The North Sea Brent field, first discovered in 1971, is enjoying extended life due to the largest reservoir depressurisation scheme yet undertaken. The project is well on track, with gas production higher than forecast.

Electrical submersible pumps have been installed to back-produce water from the reservoir in order to

Brian Slessor, Project Manager, Shell UK (right), receives the Technology Award from sponsor Rocco Valentinetti, Research and Development Coordinator, Eni

Michel Conte, Managing Director, Total E&P UK, presents Austin Hand, Venture Manager; Ian Bishop, Project Manager; and David Choat, Offshore Project Manager, with the International Platinum Award



Malcolm Brown receives a Highly Commended certificate for the 'Mahanagar Gas: Working with the pipe-walkers' project replenish the gas cap, ensuring delivery of gas. The operating environment is particularly harsh due to a combination of heat, wellbore solids and gas. To meet this challenge, a range of specially designed centrifugal pumps was developed.

Currently, 12 systems are being deployed. Each uses the largest power cable, plus the highest rated motor, used to date offshore. At 1,250 horsepower, these motors have pushed the technical limits of the technology, thus ensuring maximum exploitation of mature assets.

international platinum award

Sponsored by: Total

Winner: Shell Exploration and Production – 'Goldeneye: World class technology'

Shell Expro drilled the Goldeneye discovery well in October 1996. Recoverable reserves from the reservoir are in excess of 500bn cf of gas and 17mn barrels of condensate. At an initial supply rate of 300mn cf/d, Goldeneye will supply 3% of the UK's gas requirement in 2006.

A conventional field development solution for Goldeneye would have deployed a manned processing platform to separate the gas and liquids offshore. The dry gas and condensate would be evacuated via separate gas and liquid lines to shore. However, the business case for Goldeneye using this development solution was not robust and it could therefore not be recommended for funding.

The most attractive comparative option in terms of safety, environmental performance and economics was found to consist of a simple platform, not normally manned, at the field location, linked by a single new 105-km multiphase pipeline to St Fergus, with hydrocarbon processing performed onshore and remote operation and monitoring of the offshore facilities by satellite link.

This concept was selected as the preferred development option. It became known as the full well-stream transfer (FWT).

Highly commended: BG Group – 'Mahanagar Gas: Working with the pipe-walkers'

Mahanagar Gas, established in 1995, is a pioneering initiative to bring clean, safe, efficient and affordable piped natural gas to homes and businesses in Mumbai, India. In recent years, the company noted that there had been increased damage to its 1,727-km gas pipeline network, with the resulting leakages posing serious safety risks to the public.

Mahanagar Gas has always emphasised health, safety, security and environment issues. In order to tackle the problem, the company liaised with the local community to form a team of 320 senior citizen 'pipeline-walkers'. Each walker covers 2 km of pipeline twice daily. Mahanagar Gas is notified if the walker spots activity that could lead to damage to a pipeline.

Since the initiative started in 2003 there has been a dramatic reduction in gas leakage per kilometre of pipeline.

Anthony Levy, EI Council, presents Kathleen Lucey, Micropower, with a complimentary voucher for dinner for two, kindly donated by the Savoy Group as winner of the Business Card Prize Draw

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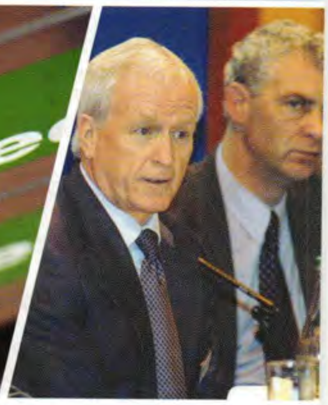

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HP/HT confidence demonstrated by Kristin

Some of the most challenging offshore developments in recent years are those where the reservoir lies over 4,000 metres under the seabed, with pressures in excess of 15,000 psi (690 bar) and temperatures over 300°F (149°C). Whilst early high pressure/high temperature (HP/HT) projects suffered set-backs, there is now confidence that these fields can be safely and economically developed. This is illustrated by the Kristin development off Norway, which will be one of the first HP/HT fields to be developed by a floating production unit (FPU). But there is no room for complacency, and strict safety precautions need to be taken, writes Jeff Crook.

Kvitebjørn is Statoil's first true HP/HT project, with reservoir pressures of 780 bar and temperatures of 150°C

One precaution on early HP/HT developments was that all production wells should be drilled into the reservoir before production start-up. The reason for this is that pressure declines sharply as production starts, giving rise to a steep (reverse) pressure gradient in the cap rocks. This precaution tended to delay projects. However, there are now signs that the rules are being relaxed, particularly where wells target different reservoir segments.

A major headache for the drillers has been the difficulty of specifying drilling fluid weight since the margin between the weight needed to control the well and the weight that can cause formation damage becomes increasingly narrow as the hole depth increases. The hot downhole conditions can also complicate the well control – for instance, by evaporation of water in the drill fluid. Today, however, well control is assisted by computerised monitoring systems.

There have also been teething problems with completions on HP/HT fields – most notably on Shearwater, where the field was shut down for around seven months soon after start-up, after high pressure was sensed in one production well. The well was re-entered by a jack-up, with damaged tubing removed for inspection. Reports suggest that some extra instruments were fitted when the well was re-completed.

Downhole problems can arise due to thermal cycling at start-up and shut-down, with the expansion and contraction of the tubing strings causing both stress and wear. Thermal expansion can also cause problems in subsea pipelines, despite the fact that flowlines will normally include dog-legs to relieve stress caused by expansion.

Achievements and set-backs

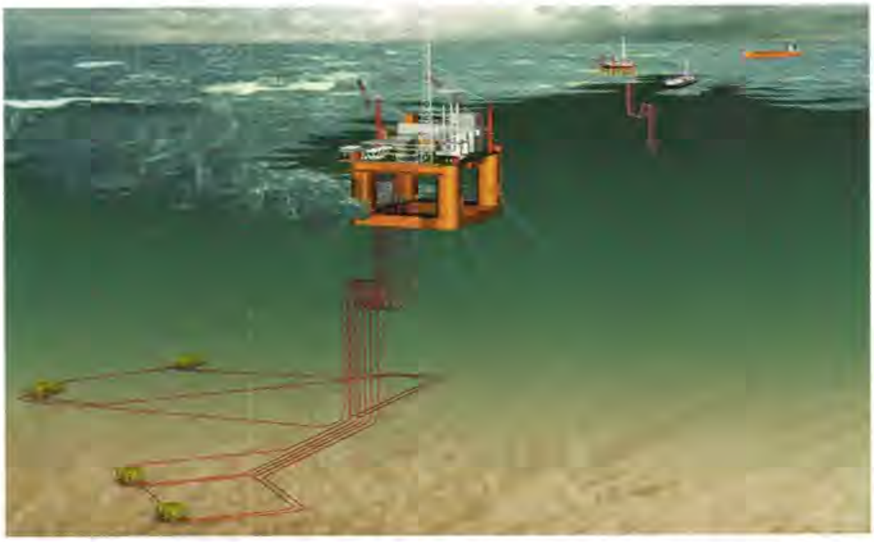
The Mobile Bay project off the coast of Alabama is thought to have the most demanding conditions for an offshore development, with bottomhole pressure of 20,000 psi (1,379 bar) at 420°F (215°C).

Closer to home, there are a number of HP/HT developments in the central North Sea – although progress here suffered a set-back when the *Ocean Odyssey* blow-out on 22 September 1988 (see p30) killed a radio operator. Many lessons were learned from this disaster, and procedures, training and equipment were significantly improved as a result. Great attention is now given to training and preparation of operating procedures. Drilling rigs now have many features to aid safety, with automated pipe-handling, top drives and ergonomic control cabins. Modern control and monitoring systems allow drillers to monitor downhole conditions from a single screen, with easy access to trends and historic records. It is also normal to incorporate 'smart alarms', which use computer intelligence to warn of hazards such as gas kicks.

Norway led the way in development of HP/HT fields in the North Sea, bringing Embla onstream in 1993. This project was followed by Lille Frigg (now decommissioned), which was notable as an HP/HT subsea satellite. Erskine was the first HP/HT field to come onstream in the UK, in 1997.

The Erskine development consists of a normally unmanned platform with hot well fluids exported by a 30-km pipeline to the Lomond platform, where they are processed. However, the subsea pipeline failed and was replaced in 2000 by an insulated pipe-in-pipe design. The pipe-in-pipe allows the transfer of thermal stress from the inner flowline to the stronger external casing, thus reducing the risk of upheaval buckling. Such a configuration is also being used for BP's Rhum development, which is due onstream in October 2005.

Erkine was followed by Elgin/Franklin, Shearwater, ETAP (which includes some subsea satellites) and Jade, all lying in the Central Graben region of the North Sea. The Elgin/Franklin project demonstrates the high rewards that can be achieved from HP/HT fields – each of its wells produces over 35,000 boe. This $2.5bn development is the largest HP/HT project so far undertaken, with downhole conditions of 1,100 bar and 200°C.



Schematic of the Kristin field, where reservoir temperature and pressure conditions are 910 bar and 170°C respectively – the most extreme conditions yet encountered in Norwegian waters

Statoil's HP/HT record

Statoil gained experience of developing high-pressure reservoirs with Huldra, although this does not qualify as an HP/HT field. The company more recently brought the Kvitebjørn* HP/HT field onstream, and is also operator of Kristin**, which is due onstream in October 2005.

Huldra reservoir conditions are 675.5 bar and 136°C. The development consists of a normally unmanned platform where well products are separated. Natural gas is piped to Heimdal and liquids are pumped to Veslefrikk for further processing. The Huldra platform is remotely controlled from Veslefrikk, and came onsteam in November 2001.

Kvitebjørn came onstream on 26 September 2004, and is Statoil's first true HP/HT project, with reservoir pressures of 780 bar and temperatures of 150°C. Recoverable reserves are put at 55bn cm of gas and 190mn barrels of condensate. Daily output is due to build up gradually to a plateau of about 20mn cm of natural gas and 62,000 barrels of condensate, with product piped to the coast.

The development consists of an integrated platform standing in 190 metres of water. The topsides are 100 metres long, with fire/blast walls to separate the process, drilling, utilities and living quarter areas. The integrated deck weighed about 11,000 tonnes, making it the heaviest offshore lift by Statoil when the *Saipem 7000* lifted it into place in May 2003.

A total of 11 production wells will be drilled by Prosafe Drilling Service for the project, together with a twelfth well for re-injection of drill cuttings and produced water. The three-year drilling programme will continue for some time after production has started. The reason that Statoil has chosen an on-going drilling programme is that the reservoir is split into various segments, with each well targeting a different one. The segmentation, however, creates problems of its own because a single well may pass through several of these segments, so pressure decline in one segment already in production will pose a challenge for wells being drilled through it. A separate project team has been established to overcome this challenge.

Innovative solution for Kristin

Kristin reservoir temperature and pressure conditions are 910 bar and 170°C respectively, the most extreme conditions yet encountered in Norwegian waters. The field, which lies 16 km south-west of Åsgard in the Halten Bank area, has recoverable reserves of 42bn cm of natural gas and 35mn cm of condensate. Estimated investment in the development project is NKr18.9bn – an increase of NKr1.7bn from the development budget set in 2001 following a change in the drilling plan.

The water depth of 315–375 metres was too great for a conventional platform so, after examining various options, Statoil and its partners settled on a plan that involves 12 subsea wells connected back to a semi-submersible floating production unit (FPU). The over-pressure protection of the flowlines is an important design issue for the project, since it would be impractical to obtain large diameter flexible risers

Ocean Odyssey disaster

The semi-submersible drilling rig *Ocean Odyssey* was working 150 miles east of Aberdeen and had reached a depth of over 16,000 ft when drilling was suspended as the result of problems with a 'thief zone' – a zone where mud is lost into the formation or where gas can enter the well bore. After withdrawing the drill bit on 22 September 1988 and restarting circulation there was an influx into the well. The blow-out-preventer failed to control this influx and gas erupted to the surface, most possibly from failed flexible hoses on the seabed. The rig was completely burned out in the subsequent conflagration.

A radio operator lost his life in this disaster – but the loss of life would have been greater if most of the crew had not been ordered to emergency stations some time before the blow-out occurred. The order to embark the survival crafts was given by the toolpusher when pressure suddenly rose in the well bore. Sadly, the radio operator had been instructed to return to the radio room to establish contact with the shore. He became trapped in the living quarters. The Offshore Installation Manager's (OIM) orders to the radio operator received strong criticism in the subsequent fatal accident inquiry.

capable of withstanding full well shut-in pressure of 740 bar.

The wells are being drilled through four subsea manifolds and will be connected by 40 km of steel flowlines and flexible risers to the FPU. Production capacity of the FPU will be 126,000 b/d of condensate and 18mn cm/d of rich gas. Product will be exported by pipeline to Åsgard.

The 14,000-tonne hull of the FPU was built at the Samsung yard in South Korea. The FPU has four columns, each measuring 18 metres by 18 metres, to support the deck above the submerged ring pontoon. The 18,000-tonne topsides were fabricated by Aker Stord, near Bergen, under a NKr5bn contract. The topsides were mated with the hull at the Aker yard during September 2004.

Choke valves will be provided at each wellhead to reduce the operating pressure in the flowlines to moderate levels of between 90 and 240 bar; while the design pressure of the flowlines is 330 bar. However, in addition to the choke valves there are three further safety systems to ensure that the flowlines are not subject to excess pressure:

- a process shutdown of the Xmas tree valves at the wellhead,
- an independent high integrity pressure protection system (HIPPS), and
- a pressure safety valve (PSV) at the platform end of each flowline.

The HIPPS system consists of two 10-inch diameter shutdown valves, each with its own activation system. Three pressure sensors monitor pressure at the manifold, with a shutdown initiated when two of these sensors register a high pressure – this is sometimes known as 'two-out-of-three' voting.

The pressure reduction from the reservoir causes temperature changes in the wellstream as the result of Joule-Thompson effects. While accurate prediction is difficult, it is anticipated that the fluids will emerge from the wellhead at over 150°C during normal production. Some cooling will therefore be required in the steel flowlines on the seafloor, to ensure that the wellstream does not exceed temperature limits set for the flexible risers. The design of the insulation system for the flowlines takes this into account.

Kristin's hydrate equilibrium temperature is 23°C, so the wellstream should be hot enough to inhibit hydrate formation during normal production. There is, however, a need to inject the hydrate inhibitor prior to a shutdown, when the fluids will start to cool inside the subsea flowlines. While dosing can be arranged prior to a planned shutdown, it would be difficult to ensure that the wellstream was adequately inhibited during an unplanned shutdown.

To deal with this problem, the Kristin flowlines incorporate a direct electric heating system similar in nature to that previously utilised on Huldra and Åsgard. The electric current is transmitted through the pipewall to generate heat, with power supplied by a cable which is strapped within the pipeline's polypropylene protective casing.

While the reservoir conditions make big demands on subsea equipment and drilling procedures, the challenge became even greater when a decision was made to drill five of the 12 Kristin wells horizontally. 'This project presents special reservoir challenges, and nobody has drilled such a formation with subsea wells,' said Nina Udnes Tronstad, Operations Vice President for Kristin, when she announced this change in May 2004.

Saipem was awarded a contract to drill the first Kristin wells using the *Scarabeo 5* semi-submersible drilling rig. A further contract was awarded to Smedvig to drill a second batch of wells using the *West Alpha*. When the first well was spudded by the *Scarabeo 5* in August 2003, Statoil's drilling operations head, Severin Longva, said: 'We've given great weight to using in-house experience and expertise in meeting these challenges and doing the job in a safe and secure manner. Experience has also been secured from other companies, and we've prepared a special high pressure/high temperature (HP/HT) manual. Eighty people in key positions on the *Scarabeo 5* drilling rig and at the operations office have taken a Kristin-specific HP/HT course.'

A total of 12 wells are due to be drilled and completed by the two rigs before production starts in October 2005.

**Kvitebjørn partners are Statoil (50%), Petoro (30%), Norsk Hydro (15%) and Total E&P Norge (5%).*

***Kristin partners are Statoil (46.60%), Petoro (18.90%), Norsk Hydro (14%), Mobil Development Norway (10.5%), Eni Norge (9%) and Total E&P Norge (3%).*

No problem, concern or crisis

A highly successful conference entitled 'Oil depletion – No problem, concern or crisis' was held at Energy Institute on 10 November. The general conclusion was that the conference was a great success with the insights it had given about depletion and should be repeated in a year or so. Petroleum Review *looks at some of the highlights of the day's proceedings.*

The conference was introduced by Professor Martin Fry, the Vice President of the Energy Institute, who started by noting the importance of the subject, particularly at a time of high oil prices. He stressed the increasing importance of energy efficiency as a way to lessen the impact of both high prices and potential resource constraints caused by depletion.

Chris Skrebowski, the editor of *Petroleum Review*, made the first presentation. He set the scene by asking a series of questions that he hoped the other speakers would answer over the course of the day. He started off by noting the variable quality of the available data, which, he claimed, was one of the reasons that the interpretations of the situation were both variable and ambiguous. It was this that enabled some to conclude there was concern, even crisis, while others were able to conclude that there was no problem.

Skrebowski went on to suggest that the reason so many had come to listen to the day's proceedings was that prices were at their highest levels since the 1978/1985 price spike, which produced the early 1980's recession; there was little or no immediate spare capacity; and economic growth was potentially threatened. After noting the economic importance to all aspects of contemporary life and the extended time required to find and develop new fields, he suggested that the question the speakers had to answer was very simple: 'Are future oil supplies primarily determined by investment levels or are they now being constrained by geology?' In short, lack of financial incentives and why, or lack of good rocks?

Dr Roger Bentley of the University of Reading was the next speaker, who gave a very comprehensive review entitled 'Global oil depletion: viewpoints in collision'. He began by noting the way that geologists generally saw peak oil as being relatively close, while economists either had it way in the future or denied the possibility of peak.

According to Bentley the main reason for this was the generally poor quality of the reserves data and the large discrepancies between the industry data (principally the IHS database) often accessible by the geologists, and the public databases usually used by the economists.

He further noted there were four key, unresolved issues which had an enormous impact on the analyses:

- The real size of Middle East reserves.
- The size and significance of discovery growth.
- The size and significance of reserves growth.
- The speed of development of non-conventional oil and oil substitutes.

Detailing the enormous size of the overall resource base in terms of currently unrecovered oil-in-place, heavy oil, tar sands and oil shales, Bentley then contrasted this apparent abundance with Colin Campbell's latest production forecasts, which indicate peak oil and liquids production around 2012. He then showed a wide range of peak production dates from various authors (mainly geologists) ranging from 2005 to 2025, followed by a further listing of forecasts (mainly economists) which either had no peak or one after 2030.

Bentley then presented a series of graphs derived from the IHS database on a strict no reproduction basis and suggested these indicate an all oil peak around 2010. He noted that the economists' counter to scenario was that it failed to credit human ingenuity, that higher prices increased supply and decreased demand, and that there was a large technology gain.

Regretting that geologists and economists were reluctant to talk, and suggesting that both could gain from greater dialogue, Bentley concluded his presentation with his own peak estimates:

- Non-Opec conventional oil: now to 2007
- Global conventional oil peak: 2010–2015
- Global all oil: 2010–2020
- Global oil and gas: 2015–2020
- Global gas: 2020–2025

A geologist's view

The next speaker was Francis Harper of BP, who spoke to the title 'Oil peak – A geologists view'. He started by showing the production profile for current reserves on a number of assumptions. He confirmed that discovery had been on a declining trends since the 1960s, but noted the upturn in discovery in the late 1990s that was associated with deepwater and the super-giant Kashagan field in the Caspian. Asking if these were anomalies or a new trend he went on to evaluate the successes and failures of the deepwater basins around the world.

He noted that some 1,500 wells had now been drilled in 120 offshore basins. Of these, 30 were productive and around 20 had commercial discoveries. Using IHS database numbers, Harper showed that the creaming curve of discovery was still rising in the four most prolific basins – Gulf of Mexico, Campos Basin, Congo Basin and the Niger Basin – indicating that further discovery is likely, even though around 55bn barrels have already been discovered.

In contrast to this optimism, Harper then noted that Kashagan was the only super-giant field discovered in the last 25 years and that the North Sea was the last major province to be opened up. Average discovery size had fallen to around 50mn boe by 1980 and had stayed at this level ever since – apart from a temporary jump to 100mn boe around 2000, which was associated with the impact of Kashagan and deepwater discovery. However, the success rate for wells had increased steadily from the one-in-six of the 1950s to the current one-in-three.

While conceding that exploration performance was somewhat disappointing, Harper explained that the major positive change was the way that discovery estimates grow with time. Contrasting IHS data in their 1997 and 2003 reports covering the period 1950 to 1996, he showed that the reserves estimate had increased by 200bn barrels – although he did concede that most of the gain was in the larger older fields. He also showed that during the 11 years to 2003, the IHS estimate of cumulative discovered volumes to 1990 has increased by an average of 40bn b/y. He explained that field estimates grow either by increases in hydrocarbons-in-place (extensions, additions) or by increases in recovery factor (revisions, improved recovery). This growth in reserves more than compensates for production and disappointing discovery.

Harper also presented some graphs

showing the recovery factor by number of fields and volume of reserves. By number, the most common is a recovery rate of 30%–35% by volume; although the peak is at 35%, large volumes show recoveries up to 55%.

The remainder of the presentation examined the potential for various alternatives – heavy oil, bitumen (tar sands), shale oil, gas-to-liquids and biofuels.

His overall conclusions were:

- Existing discovered reserves are unlikely to sustain demand for more than about 15 years.
- Exploration cannot be expected to replace production and its contribution may continue to decline.
- Reserves growth is likely to continue as the dominant form of reserve additions, but much of it will only slow post-peak production decline.
- Non-conventional oil will become increasingly important – there is a very large resource but converting it into reserves has significant financial and environmental costs.
- Non-Opec is likely to reach a resource-constrained production peak from conventional oil in the next 10 years – thereafter, production capacity will be concentrated in progressively fewer countries.

Long-term future

Professor Peter Odell followed, with a presentation entitled 'Oil's long term future – 85% yet to be exploited'. He started by noting that concerns about future oil supply have been a recurring theme – as encapsulated in the pamphlet *Oil Crisis... Again?* (BP, 1979), which foresaw oil production outside the Soviet bloc peaking in 1985. Professor Odell then explained that such analysis failed because of the rigidity of the assumptions about discovery and the 'absurd notion that oil had a perfectly inelastic supply price curve'. He then went on to explain that, using the publicly available reserves databases, discovery had handsomely exceeded consumption – meaning that the world was 'running into oil' rather than 'running out of it'.

Odell also commented that the application of new technology was still largely confined to Europe and the US, and that once its impact was fully felt in areas such as the Middle East and the former Soviet Union, there would be a major uplift in production and reserves.

He contrasted this dynamic analysis with that of those who saw supply constraints emerging in the near term. He developed this dynamic approach (financial incentives drawing forth incremental supply) further, by presenting a plot of ultimate reserve assessments over time, which showed the way the estimates' trend towards an ultimate of 2,700–3,400bn barrels. Odell then went on to look at the potential contribution of non-conventional oil, showing graphs in which conventional oil production peaks around 2025–2030 and non-conventional peaks around 2090. Combined, this gives an overall peak in 2060 of around 6.8bn toe.

By showing the range of additional supply sources and establishing the economic response to the price signals, Odell stated that he felt confident in saying that future oil supplies presented 'no problem' for the foreseeable future. He also noted that all the current analysis tended to be done on the basis that oil had an organic origin. He drew attention to the Russian-Ukrainian theory of oil's abyssal, abiotic origin, pointing out that this could remove the remaining constraint on oil supply if it proved correct.

Middle East dramatics

In what was in many ways the most dramatic presentation of the day, Dr Michael Smith of EnergyFiles spoke to the title 'Middle East miracle or mirage?' He started with a series of slides showing the way recent peak production of 22.5mn b/d came from 11 producers, with the Middle East five (ME5) – Iran, Iraq, Kuwait, UAE and Saudi Arabia – accounting for 20mn b/d. In succeeding slides he showed how, despite the growth in offshore production, total world oil production, excluding production from the ME5, would peak by 2010 and then move into decline. He then showed the volumes needed to be produced from the ME5 to meet demand growth of 1.5% and to offset the decline in all other producers after 2010. Extrapolation of this showed that the ME5 needed to produce over 75mn b/d by 2030 to meet 1.5% growth.

Smith then explained that he would 'believe' the stated production expansion targets of the ME5 and proceeded to graph them. The graphs showed that 1.5% demand growth would produce a peak in 2013, with some potential excess production capacity in the run up to 2013. However, if demand growth was at 2.5%, the peak production occurred in 2010. And, most dramatically of all, if demand growth proceeds at 3.5%, then global peak is now.

He pointed out that ME5 reserves and capacity can be endlessly debated, but, even taking their own ambitious capacity estimates, the sort of demand growth known for the last 30 years cannot be sustained for another decade.

Smith's summary was equally dramatic: 'Before peak, supply has moved to meet demand. After peak, demand will drop to meet supply.'

Exaggerated concerns

Dr Rob Arnott of the Oxford Institute for Energy Studies spoke next, with a title for his paper of 'Oil depletion or depleted policies'. In the course of his presentation he explained that he saw four reasons for the failure of the oil companies to develop new production capacity in time to avoid the recent tightness and high prices. These were lack of exploration activity caused by inappropriate oil price assumptions, manpower constraints caused by an ageing workforce and over-eager downsizing, corporate strategies that set unreasonably high rate of return requirements and, lastly, working with legacy assets designed to optimise returns rather than production. His view was that more appropriate policies would largely ameliorate the situation.

Optimistic outlook

The final presentation of the day was given by Dr Ken Chew, Vice-President–Industry Performance and Strategy for IHS Energy. In the course of his presentation Dr Chew presented a large number of slides drawing on IHS database information. While this broadly confirmed the pattern of declining discovery and lack of recent large field discoveries, data providing a rather more optimistic outlook was also shown.

A detailed analysis of the non-conventional resource plays was given, showing the sheer size of the potential heavy oil, tar sand and shale oil resource base. Details were presented of the way both Orinoco heavy oil and Canadian tar sands production was building up and their future trajectory. Detailed analysis of both oil and gas reserves were also given, with comparisons made to the public databases. One of the most important slides showed how discovery in the 1995–2003 period of 144bn barrels was exceeded by consumption of 236bn barrels. However, revisions and reassessments of pre-1995 discoveries had added 457bn barrels of reserves (over half in the Middle East). Of this total, around 190bn barrels was resource growth/reserves growth/field growth, while the balance was new data/under-reporting/missing data.

The conclusion was that, if all of the resource base was included and the high estimate for yet-to-find used, global oil resources were only 25%–30% depleted and gas resources only 20% depleted.

The rest of the conference featured a question and answer session, with the panel of speakers mediated by Richard Hardman, a Past President of the Geological Society. Although the debate became quite heated on occasions, it was well received and most regarded it as a successful day.

High taxes to impact future Russian production?

Recent news about the situation in the Russian oil sector has been largely confined to reports about two or three major oil companies. The Yukos saga has dominated, but there are other trends in the Russian oil sector that influence the country's economy, writes RIA-Novosti Economic Commentator Nina Kulikova.

The oil industry is Russia's most profitable sector and is developing intensively, with production expected to exceed 450mn tonnes this year. Traditionally, Russian businessmen are more optimistic in their forecasts for oil production growth rates than government officials and the scientific community. Andrei Gaidamaka, head of the Investment Analysis and Investor Relations Division at Lukoil, predicts steady production growth of between 4% and 5% annually. Meanwhile, the President of the Energy Policy Institute, Vladimir Milov, believes a figure of 1%–2% a year is more realistic.

Any potential growth of Russia's oil production and exports depends on investment, the introduction of new technologies, major systemic solutions concerning the construction of new pipelines and the development of deposits in Eastern Siberia. According to Andrei Klepach, Director of the Macroeconomic Forecasting Department at the Russian Ministry of Economic Development and Trade, a maximum of 500mn tonnes of oil will be produced by 2010 if infrastructure and new deposits are not developed. However, if the government focuses on infrastructure problems by launching the construction of new pipelines – particularly to Nakhodka and Murmansk – and increasing the capacity of the Baltic transportation system, Russia will be able to produce between 530mn and 550mn t/y of oil.

Two problems

Two problems are to blame for these modest forecasts. First, many oil companies are in no hurry to invest in oil production because of low transport capacities. Large volumes of exported oil are transported by rail and ship, which is two to three times more expensive than pumping it through a pipeline. Transportation is the second largest expense item after taxes on the balance of Lukoil. According to Gaidamaka, the Russian pipeline system does not completely meet Russian oil companies' export demand.

Klepach says proposals on pipeline construction are included in a medium-term programme drawn up by the Ministry of Industry and Energy, which has been presented to the Ministry of Economic Development and Trade and will be submitted to the cabinet. At the same time, a corresponding resource base, ie existing cost-effective oil reserves, must cover the creation of new transportation capacities. It is doubtful that this base exists, as production is increasing slower than exports. In the future it will become increasingly difficult to guarantee growth in production and exports from reserves in Western Siberia.

The second problem is the instability of the taxation system and differences in the government on how to improve oil sector taxation. Under the current system, if the price of oil is higher than $25/b, oil companies lose up to 90% of additional revenue to pay taxes. Even representatives of the Ministry of Economic Development and Trade doubt that new deposits can be developed and capital-intensive projects implemented in such conditions.

While giving credit to the government for its successes in collecting taxes, businessmen, however, point out that the burden on the oil sector is so great that it affects investment decisions. Over the last three years, Lukoil's tax payments have gone up more than twice against the backdrop of a 100% increase in oil prices. Consequently, Gaidamaka sums up that, with the growth in world oil prices, companies' surplus revenues are transferred to the budget. After new taxation rules are introduced in 2005, oil companies will lose more funds than they may yield from oil trade to pay taxes, comments Galina Antonova, head of the Yukos Analytical Department.

Call for tax revisions

Representatives of oil companies and government officials are unanimous that the tax burden on the oil sector is approaching a critical point, which means that taxation policy in this sphere needs to be revised. The problem is how to alleviate the burden. At present, the export duty and the tax on natural resources production, which is pegged to the world oil prices, account for the lion's share of tax payments. One of this system's great disadvantages is that a slide in world oil prices may hit domestic production hard. Besides, the tax on natural resources production hinders the development of new deposits. According to Arkady Dvorkovich, who heads the Presidential Expert Department, dependence of the tax on natural resources production on world prices makes domestic prices for oil products higher. The majority of experts believe companies' profits and not natural resources production should be taxed.

Whether it is possible to reform the taxes has been widely discussed lately. The Ministry of Economic Development and Trade is in favour of keeping and differentiating the tax on production. For example, one proposal is that the tax should be lower on new deposits and ones close to depletion, but it should be independent from the world prices. However, these measures must be seriously thought through, otherwise the move may favour one party over another. There are also proposals to abolish the export duty and introduce additional profit taxes to make up for falling budget revenues.

Stable legislation is the most important factor. Only in this case will companies be able to make plans for the years to come. Developing the oil sector and making it more attractive for investment are highly important for the state, because revenues from oil sector taxation account for a large part of the federal budget and the country's stabilisation fund.

SPE London Section Evening Meeting
Tuesday 25 January 2005

Power to the People 5–6.30pm
Vijay V Vaitheeswaran

Global Environment and Energy Correspondent
The Economist

- How the Coming Energy Revolution Will Transform an Industry, Change Our Lives, and Maybe Even Save the Planet. Vijay will highlight the trends he believes will transform the energy game: liberalisation of the energy markets, the increasing influence of the environmental movement and recent innovations in hydrogen fuel-cell technology.
- Vijay is a term member of the Council on Foreign Relations. He has delivered lectures at Stanford, Harvard, Yale and Columbia, and is an adjunct faculty member at New York University. He is a regular commentator on NPR's Marketplace program, and a frequent guest on PBS, BBC and CNN. **www.vijaytothepeople.com**

'Vaitheeswaran's new book, *Power to the People*, is by far the most helpful, entertaining, up-to-date and accessible treatment of the energy-economy-environment problematique available', Professor Holdren, Director of the Program on Science, Technology and Public Policy, Harvard. Copies of Vijay's book will be available.

Investing for Production: A stock market perspective 8–9.30pm
J J Traynor

Managing Director Global Oil and Gas – Deutsche Bank

- Stock market listed oil companies face the challenges of rewarding shareholders, and investing in long-term solutions to OECD declines. This presentation will assess the macro-economic outlook for the oils, key financial and political trends, and strategies for reserves replacements.
- JJ works in the global equities division that assesses company valuations and strategies in the global oil sector, and the implications for share prices. He is a geologist by background, and has a PhD from Cambridge University. He worked extensively in exploration projects, prior to joining the banking industry.
- Deustche Bank is one of the world's largest investment banks. The global equities division is orientated to providing advice on share prices and company valuations to institutional investors, primarily in the pension fund industry. European operations are concentrated in London.

Drinks and sandwich buffet (6.30-8 pm)

Tickets inc. drinks and sandwiches: £30 members and affiliates, £40 other.
t: 020 8476 8684 (for Visa/Switch); e: **Katespe@aol.com**; Kate McMillan, 07736 070066.
Venue: The Geological Society of London, Burlington House Piccadilly, London W1.
150 persons only – pre-booking is strongly advised.

Photo: David Hayes

Coal imports to feed power generation growth

Although the Malaysian government is keen to promote oil and gas to drive economic development, it favours imported coal to feed the country's future power generation growth, writes David Hayes.

With strong energy demand forecast in the Asia-Pacific region over the next few years, expected sustained high petroleum prices are likely to create new economic opportunities for Malaysia. The country is projected to see a GDP growth rate of 6% in 2005 – based on a vigorous economic recovery – although a little lower than estimated 6.8% growth in 2004. Higher oil prices and demand are expected to encourage new investment, and a number of new exploration agreements have been signed since mid-2004. Deepwater exploration is growing, driven by oil companies' expectations that higher prices will continue for some time.

Malaysia's crude oil reserves, including condensates, rose 6.6% to 4.84bn barrels at the start of 2004 following several new discoveries the previous year. Natural gas reserves fell, however, to 87tn cf from 89tn cf one year earlier as few additional reserves were found. Domestic production of crude oil and condensates rose to 274.6mn boe (an average of 750,200 boe/d) – up 7.1% compared with 256.4mn the previous year. Production of gas was in excess of 4,300mn cf/d, with over half being used for LNG production.

At the current rate of production, Malaysia's oil reserves are expected to last another 18 years; while sufficient gas reserves are in place to last another 34 years.

Strategic sector

Energy has been one of Malaysia's strategic sectors for some time and state-owned Petronas has been busy expanding its activities in many parts of the world. Similarly, Malaysia's electricity companies have become international in outlook, buying power plants and other resources overseas.

According to Azizan Zainul Abidin, Chairman of Petronas, the company currently accounts for about 75% of Malaysia's oil production and is keen to join the ranks of the world's oil majors. The company's increasingly global portfolio of oil and gas E&P investments now numbers 57 ventures in 35 countries as part of efforts to offset the decline in domestic energy reserves. Investments in Iran and Egypt boosted Petronas' international reserves to 25% of its total oil and gas reserves in 2003, compared with 20% the previous year. Overseas capital expenditure of RM11.9bn now exceeds domestic expenditure of RM10.4bn, while total capital expenditure of RM22.3bn in 2003 was 35.4% more than that RM14.4bn spent the previous year.

Meanwhile, gas use is rising in Malaysia where domestic demand has risen in the Peninsular. In addition, the commissioning of MLNG Tiga – the third LNG plant in Sarawak – also will raise gas use as LNG production grows to meet contract agreements.

At present, about 2,000mn cf/d of gas is transmitted ashore daily from offshore gas fields in the South China Sea. After being processed as feedstock by the Petronas gas separation plant in Kuantan, gas is supplied through the Peninsular pipeline grid to various customers. Peninsular Malaysia's gas transmission grid measures more than 1,920 km in length and consists of 1,750 km of main gas pipelines and 170 km of lateral pipelines. The grid route runs from

Kerteh to Segamat, Segamat to Changlun in Perlis state near the Thai border in the north, and Segamat to Johor Bahru in the south, from where a short spur supplies Senoko power station in Singapore.

Security of supply

Security of gas supply in Peninsular Malaysia will be increased shortly when construction of the Thai-Malaysia gas pipeline across southern Thailand is completed, to transmit offshore gas from the Joint Development Area (JDA) gas field owned jointly by Thailand and Malaysia in the South China Sea. A 277-km, 34-inch diameter submarine pipeline capable of transporting 1,020mn cf/d has already has been constructed from the JDA gas field to landfall near Chana in southern Thailand's Songkhla Province, where the pipeline comes ashore and feeds a new gas processing plant.

Due for completion in mid-2005, a 97-km, 36-inch diameter cross-country pipeline capable of carrying 750mn cf/d is also being constructed, from Chana to run south-east to Sadao on the Thai border with Malaysia. From there the pipeline will continue south through Kedah State in northern Peninsular Malaysia to connect with the northern end of Petronas' west coast Peninsular gas pipeline. In addition, running parallel to the natural gas pipeline, a 240-km, 8-inch diameter LPG pipeline is being built from the Songkhla gas processing plant to Kedah, from where the LPG pipeline will continue south to the Petronas LPG receiving terminal at Prai in Penang State.

Trans Thai-Malaysia (TTM) is building the Thai-Malaysia pipeline and Songkhla gas separation plant. PTT, Thailand's gas transmission, distribution and sales monopoly, and Petronas both have equal 50% shareholdings in TTM, which will own and operate the Thai-Malaysia pipeline and Songkhla gas separation plant upon completion.

Construction of the Thai-Malaysia pipeline will provide Peninsular Malaysia with security of gas supply by transporting gas from the JDA field through the northern pipeline loop across southern Thailand to the west coast of northern Peninsular Malaysia. Petronas has chosen this gas transmission route rather than build a longer submarine pipeline from the JDA field to connect with Malaysia's producing Esso gas fields in the South China Sea that supply gas through the submarine pipeline grid that transmits gas ashore at Kuantan on the Peninsular east coast.

The Thai-Malaysia pipeline will transmit Malaysia's 50% share of the JDA gas reserves for Petronas to supply to customers in Malaysia while PTT is planning to use Thailand's 50% share of the JDA gas reserves in the future to supply the Khanom and Surat Thani power stations in southern Thailand.

Gas reserves and imports

Malaysia has among the largest natural gas reserves in Asia. The reserves are divided about 40:60 between Peninsular Malaysia, where they lie offshore the Peninsular east coast in the South China Sea, and East Malaysia, where they lie offshore, mostly off Sarawak. Gas reserves off East Malaysia have been allocated for the production of LNG and fertiliser for export. LNG markets include Japan, South Korea and Taiwan. Peninsular Malaysia is the country's main population and economic centre. As a result, the government has set aside the Peninsular offshore gas reserves for domestic use. Most of the gas will continue to be used for power generation.

In addition to its offshore Peninsular gas reserves, Malaysia imports piped gas from Indonesia and plans to increase imports in the future. In August 2002 Petronas started to receive 100mn cf/d from Indonesia's West Natuna field under a 20-year contract that will see gas imports grow to 250mn cf/d by 2006.

Pertamina, Indonesia's state oil and gas company, is supplying gas to Petronas through a 100-km, 18-inch diameter subsea pipeline that connects the West Natuna field with Malaysia's Esso-operated offshore Duyong field in the South China Sea. From Duyong, the West Natuna gas is transmitted through the existing subsea pipeline grid that comes ashore at Kerteh on the Peninsular Malaysia east coast.

Malaysia recently announced plans to increase gas imports from Indonesia. In August 2002 Pertamina and Petronas signed a memorandum of understanding (MoU) under which Petronas will import 300mn cf/d from several gas fields in South Sumatra. Petronas and Pertamina are believed to be studying several pipeline route options for the subsea pipeline section to cross the Malacca Straits from Sumatra to Peninsular Malaysia, where Indonesian gas supplies will be fed into the Peninsular pipeline grid.

The subsea pipeline across the Malacca Straits is due to form part of the Asean gas pipeline grid that will also include a second subsea pipeline from North Sumatra to Peninsular Malaysia. Construction of both pipeline sections will depend, however, on Indonesia building the two Duri-Medan and Medan-Arun gas pipeline sections of its proposed north-south trans-Sumatran gas pipeline.

Multi-fuel policy

Although Malaysia's gas reserves have many years to run, state-run Tenaga Nasional (TNB), which supplies power in Peninsular Malaysia, has adopted a multi fuel policy following concern that the electricity industry had become over dependent on gas. TNB's plans call for coal-fired generation to increase to 20% of Peninsular Malaysia's total electricity output before 2010, and for hydroelectric power also to grow to 20% of output, thereby reducing the gas-fired share of generation to about 60%.

At the end of 2003, power stations with a combined installed capacity of about 16,987 MW were operational in Peninsular Malaysia. TNB gas-burning power stations, including combined cycle stations with a 2,050 MW capacity, had a total installed capacity of about 3,700 MW – representing 22% of Peninsular Malaysia's installed capacity. Independent power producer (IPP) plants, which are almost entirely gas-fired, totalled about 6,834 MW and accounted for a further 40% of the Peninsular's total installed capacity.

At the end of 2002 TNB's installed coal-fired generating capacity stood at 2,980 MW, representing 11.2% of Peninsular Malaysia's total installed capacity. Hydropower plants, meanwhile, totalled 1,911 MW installed capacity and accounted for 11.3% of Peninsular Malaysia's total installed capacity.

After burning 4mn tonnes of coal in 2001 at Kapar power plant, which has coal-fired units totalling 1,600 MW, TNB's coal use has more than doubled to 9mn tonnes annually with the completion of Manjung power station in 2003. Coal is imported from major coal producing countries including Australia, China, Indonesia and South Africa.

Although TNB plans to use imported coal for almost its entire needs, Malaysia has some coal reserves in Sarawak, East Malaysia. Since the early 1990s TNB has purchased 120,000 t/y of coal from the Kapit coal mine in Sarawak – which is believed to be the only coal deposit currently being worked in Malaysia. The Kapit mine also delivers 400,000 t/y of coal to Sarawak Electric Supply Co (SESCO), which supplies electricity in Sarawak State.

Peninsular Malaysia's coal import needs will double to 20mn t/y once two planned coal-fired IPP power plants are fully commissioned by 2010. Construction work has started on the 2,100-MW Pulau Bunting power station that will burn 6mn t/y after the plant's three units are

Photo: David Hayes

commissioned in 2007 and 2008.

However, the scheduled commissioning of the 1,400-MW Jimah power plant has been deferred to 2010 – the two 700-MW units were originally planned to start in 2007 and 2008 along with Pulau Bunting. When fully operational Jimah will burn 4mn t/y of coal.

TNB's other coal procurement strategy recently has involved the corporation in purchasing its own coal mining operation in Indonesia with the aim of securing low coal prices and improving security of coal supply. The company's plan is to buy 30% to 50% of its annual coal requirement from its Indonesian mine, with the remaining tonnage being purchased on the open market.

Following the recent installation of a new coal crusher at TNB Coal's PT Dasa Eka Jasatama coal mine, the company aims to increase its overall production to 2.6mn tonnes in 2005.

Hydro potential

Meanwhile, large hydroelectric power potential awaits development in East Malaysia, where the main limitation is the relatively small population size and limited industrial development. The state government of Sarawak – where some 51 hydropower projects have an exploitable potential of 20,000 MW and an energy output of 87,000 GWh annually – is hoping to attract energy hungry industries and spur economic growth.

At present, the 2,400-MW Bakun dam – the first large project planned to develop part of Sarawak's hydropower resources – is believed to be under government review after Malaysian Prime Minister Abdullah Badawi earlier said he wanted to reduce spending on big infrastructure projects. These had been promoted by former Prime Minister Mahathir Mohamad. However, the government may decide to restructure the Bakun project or cut the dam's power capacity because of doubts over electricity demand growth.

In 1994 the government decided to implement Bakun dam as an independent power producer (IPP) project targeted for commissioning in 2003. However, following the impact of the Asian financial crisis in 1997–1998, the original government-appointed Bakun dam project developer, Sarawak tycoon Ting Pek Khing, was unable to proceed with the project and returned it to the government, receiving RM420mn compensation.

After deferring the project for three years the government has decided to revive Bakun, which now is being undertaken by Sarawak Hidro, a wholly-owned subsidiary of state-owned Minister of Finance Incorporated.

Government support for the Bakun dam was due to the pump priming effect that the massive project will have on the East Malaysian economy. Originally, Bakun was planned to supply 1,500 MW of its power output to Peninsular Malaysia through a subsea transmission cable to help diversify the Peninsular's growing power needs. Constructing the subsea cable has now been abandoned as too costly. Instead, Bakun's largest customer, using 900 MW, will be an aluminium smelting plant that is due to be built as part of Sarawak's economic diversification programme.

At the end of March 2003 Sarawak Hidro and Smelter Asia announced that they had reached agreement on the proposed bulk sale and purchase of electricity to be generated by Bakun dam, following the earlier signing of an MoU between the two parties. Smelter Asia, a joint venture company between Gulf International Investment Group (GIIG) headed by Malaysian tycoon Syed Mokhtar Albukhary and DUBAL, will develop an aluminium smelting plant on a 250-hectares site at Similajau near Bintulu on the coast of Sarawak. Construction of Smelter Asia's aluminium smelting Phase 1 project for the production of 250,000 tonnes of aluminium ingots per annum is due to begin in 2005.

According to the recently signed power purchase agreement the amount of electricty to be purchased under the Phase 1 project is about 450 MW.

The aluminium smelting production capacity is expected to double to 500,000 tonnes when Phase 2 is completed by 2012. As a result, the power purchase requirement will double to 900 MW.

In return, the Mahathir administration in 2003 agreed to sell a 60% stake in Bakun to GIIG in a closed privatisation deal. However, the fate of the smelter project has been in question since December 2003 when DUBAL pulled out of the scheme. The new Prime Minister Abdullah cancelled the deal soon after coming to power in October 2003 – although the government has since said it may proceed with Bakun's privatisation in the future. Only time will tell.

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BIEE
British Institute of Energy Economics

Tuesday 11 January 2005, 5.45 pm

Dr Paul Horsnell, Barclays Capital

will speak on
'Oil Markets in 2004 and the Outlook for 2005'

at The Auditorium, BP plc,
1 St James's Square, London SW1

Contact: BIEE Administration Office, 37 Woodville Gardens, London W5 2LL or e: **admin@biee.org** by Friday 7 January 2005

Oil depletion – No problem, concern or crisis
A very successful conference on the impact of oil depletion was held at the EI on 10 November 2004 (please see write-up on p32).

This is a subject on which there is a wide diversity of ideas and opinion. We would like to encourage some coverage of this by asking readers to write letters to the Editor on the subject which will be printed in future issues of *Petroleum Review*.

Unravelling the benefits of energy liberalisation

Despite the considerable anecdotal evidence suggesting that energy competition has been bad for residential customers, Datamonitor's Daniel Legg *argues that an analysis of the benefits of market liberalisation needs to look beyond residential retail prices. Indeed, a liberalised residential market is an important component of a fully functioning liberal I&C (industrial and commercial) market.*

Some breathtaking recent price rises have led industry watchers to ask whether energy market liberalisation has benefitted customers, and a PhD thesis by a Platt's editor, who was based at the University of Sussex, claimed that the cost of introducing competition into the power market has outweighed any savings made by consumers. Although neither of these criticisms need apply across the rest of Europe, liberalisation has been hesitant in many EU countries, and the case in favour is by no means universally accepted.

Although the benefits of residential gas and power market liberalisation are diffuse and complex, it can be argued that there are benefits even in the narrow economic sense of prices. There are three components that make up the retail price for energy paid by residential consumers – generation/production costs, transmission and distribution/shipping costs, and supply costs. We need to look at them separately when we evaluate the connection between liberalisation and price movements.

Generation and wholesale prices

The introduction of competition into UK power markets brought about a precipitous drop in wholesale prices, much to the detriment of British Energy and the merchant generators. This, in turn, can be attributed to three factors:

- The profit motive induces generators to optimise their fuel mix, both in short-term decisions on how to produce peak load, and in long-term decisions concerning new build.
- Fuel procurement practices – generators procure fuel as efficiently as possible, not allowing ambiguous considerations like 'the national interest' to influence their decisions.
- Generators build and manage their assets as efficiently as possible. Importantly, they are encouraged to retire inefficient plants rather than run them at a loss. Unfortunately for the free market argument, this arguably is achieved at the expense of security of supply.

Although the above factors tended to force down both wholesale and retail prices in the UK after the introduction of the New Electricity Trading Arrangements (NETA), prices could not remain depressed forever. But this does not mean that the above factors ceased to apply – the current rise in UK wholesale prices can be attributed to a reduction in capacity and, most importantly, a rise in commodity fuel prices. Liberalisation of the wholesale market cannot terminate the cyclical nature of commodity fuel prices; but it should train utilities to adjust to such cycles in the most efficient way possible.

This is not to say that power prices have, or will, fall in every European market after liberalisation. The three factors outlined above are only some of the drivers that determine price levels, and their effects cannot easily be distinguished from short-term market anomalies or from long-term commodity cycles. Prices crashed in Germany after liberalisation, while various commentators are warning that prices will rise in France – although predictions coming out of France are sometimes politically motivated. What we can say is that there is no strong case to say that the removal of the market inefficiencies common in non-liberalised markets will not exert downward pressure on prices.

Liberalisation of gas wholesale markets would not have such a marked effect. By its nature, the upstream gas market in many European countries has never contained many of the inefficiencies suffered by the pre-liberalisation UK power market. Hence further reductions in wholesale prices rely on increased participants entering any particular national market, and on increased access to network capacity. Theoretically, market liberalisation is often the precursor to the creation of a spot market, and so an increase in buyers and sellers, resulting in a reduction in prices. But, in practice, the lack of network capacity will mute any benefits, certainly for the next few years.

One other way in which liberalisation could bring about a reduction in wholesale prices is by decoupling the gas price from oil. With oil prices currently at record highs, removing its link to the gas price would make a significant difference to consumers. Unfortunately, it would take many years for the benefits to reach them, because there are still many contracts indexed to oil prices that have many years left to run, and because continental gas wholesale markets are not yet sufficiently liquid to support this to any meaningful degree.

There are some cases of market inefficiency in upstream gas markets, depending on the strategic objectives of those who planned them. For instance, UK planners ensured that gas could not be imported into the country through interconnectors or LNG terminals. This encouraged the development of the UK Continental Shelf by guaranteeing a domestic market, but perhaps not guaranteeing the lowest prices for end users.

Transmission and distribution costs

A second factor in the reduction of retail energy prices has been the reduction in transmission and distribution prices. Ofgem has achieved this in the UK by pegging permitted access charges to the performance of the most efficient network operators, thus encouraging the remaining players to improve performance if they are to make a return. However, it is fair to acknowledge that all of this could have been possible without competition – distribution companies are still regulated monopolies.

Some European network pricing regimes were based on negotiated third-party access before July 2004, but the gas and power directives have obliged EU states to move over to a regulated system where tariffs are agreed by a regulator. Although this process may not itself directly lower prices, it should encourage competitors to enter previously protected regions, potentially lowering prices as a consequence.

Supply costs

The third component of retail prices – supply costs – in fact rose with the advent of competition. In short, suppliers chasing customers suddenly had to cover sales and marketing costs that had never been an issue before. However, this need not be a permanent characteristic of the market. The reduction of 14 UK electricity boards to six large energy retailers certainly resulted in synergy savings, while suppliers made great strides in reducing their internal process costs – although none of this outweighed the high cost of acquiring new customers.

This process of consolidation has even more potential in Italy, France, central Europe and Scandinavia, where many markets are highly fragmented. The pace of consolidation and cost cutting has not always been as rapid as possible, but Datamonitor's own research shows that the process was given another fillip during the summer 2004 round of liberalisation, even in markets that had been liberalised long before then.

In the UK, frenetic switching in the residential market was followed by a period of relative calm, with most suppliers concentrating on controlling costs, partly by slashing their sales and marketing budgets. An industry-wide initiative to improve the switching process should result in a further reduction in costs, and also do a lot to assuage customer dissatisfaction.

We do not have to be too kind to UK suppliers though – their notoriety is mostly deserved. However, the costs of introducing competition and of rectifying mis-selling scandals are not supposed to be eternal – the economic benefits will last.

Benefits of choice

The benefits of liberalisation are not simply price related. There are several positive consequences of a consumer's ability to choose and the symmetrical ability of energy suppliers to acquire new customers. One of the most important is the rapid development of new energy and energy related products.

Liberalisation implies that utilities can expand beyond their core product, enabling them to increase profits by selling extra services to their existing customer base. It also allows them to drop prices to consumers by bundling products – it costs much less to serve gas and electricity to one customer than to provide two customers with electricity alone. Hence the development of dual fuel, home services, and a fully-fledged multi-utility supply package that includes telecoms and the Internet. This expansion of services will allow the development of a whole concept of 'services for the home' encompassing appliances, insurance and energy saving products as well as the basic utility services.

As well as product innovation, the need to differentiate products and to meet customer needs has led to a multiplication of tariff structures in an effort to suit varied segments of the residential market. There are now online tariffs for people who are prepared to be proactive in return for lower prices, green tariffs for the environmentally concerned, a flat tariff for the elderly, various levels of standing charge, capped tariffs for the cautious, and affinity deals for those who want to support a favoured organisation. Consumers in Germany can choose from a number of lifestyle tariffs, and Scandinavians can have tariffs linked to either the forward or spot price of the wholesale market.

Despite frequent news of underwhelming customer service from UK utility companies, the need to keep customers has led to an increase in investment in this area of their operations. However, the industry's intentions have admittedly been impaired by the (hopefully transitory) problems arising from an unsatisfactory switching process. On the other hand though, online meter reading, compensation for missed meter reads and improved bill accuracy have all made life that little bit better. We can also look forward to the spread of automatic meter reading, which is already being introduced in some European and American regions.

Naturally, none of this would have been impossible in a non-competitive market, but the drive to innovate has led to a marked quickening in the improvement of choice and quality of service.

The European angle

A less recognised benefit of market liberalisation comes from the impact it has on European integration. This can be seen in three main ways. Firstly, it fosters increased competition. The arrival of powerful new entrants drives down prices and can introduce best practice. This applies to gas as well as to power; and the wholesale market as well as the retail market. Building interconnectors effectively diversifies the potential sources of both gas and power, increasing the liquidity of wholesale markets, while allowing more sellers into the retail market reduces the likelihood of oligopolies forming.

Secondly, a European-wide power generation market should be able to meet the continent's energy needs more efficiently than several individual national markets. This works best when generation portfolios are planned on a continental scale – building hydroelectric power stations where there is rain and mountains, nuclear power stations where there is space and CCGT (combined cycle gas turbines) where there is gas. This way, each individual country does not have to achieve a wide spread of fuel types. This is a variation of Ricardo's theory of comparative advantage that underpins many modern trading patterns – if each country specialises where it has a comparative advantage, they all grow richer.

The third benefit is more dewy-eyed – the energy industry is too important to the continent's economic and social well-being to be riven by international rivalry. It is argued that the development of a European wide market, with cross-border trading and ownership, will foster amity.

Symbiotic relationship

Whereas the benefits of residential market liberalisation are often questioned, the benefits of business market liberalisation are more widely accepted. Switching is much more common in the I&C market, which forces down prices. Sales and marketing costs being relatively low, most of the benefits of falling generation and distribution costs are passed onto business users, particularly at the larger end of the spectrum. And, of course, lower unit prices for power and gas are beneficial to the competitiveness of UK industry.

Less well appreciated, and arguably more controversial, is the reason why residential market freedom is required for business market liberalisation to work. In short, a captive residential base would allow suppliers to subsidise their I&C business by passing some of the costs onto their residential base. This is not only bad for residential consumers, it distorts competition for companies that do not have a residential customer base. Using a residential customer base to subsidise industry may well result in lower prices for customers in the commercial segment, but not in a way that encourages the efficiencies mentioned throughout this article.

For this reason, critics should consider the benefits of business market liberalisation before they condemn choice in the residential market. However, a case for residential market liberalisation can also be made on its own terms. Competition has introduced long-term benefits, namely cost reduction and product innovation, which should outlive the short-term teething pains of the deregulation process.

Creating an effective gas supply network to Europe

This is the second of a two-part article in which David Wood* *and* Bill Pyke** *argue that the creation of an effective gas supply network to Europe requires the integrated development of both pipeline and LNG markets. Here, they look at the key LNG buyers in Europe and address potential gaps in future gas supplies. Part 1 of the article was published in the December issue.*

LNG will continue to provide market access opportunities to more distant producers that are too remote or geopolitically isolated for piped supplies to be a short-term option (eg the Middle East).

Six member states of the European Union (EU) – France, Belgium, Spain, Portugal, Italy and Greece – imported 25.5mn tonnes (36bn cm) of LNG in 2003 (see **Figures 1** and **2**). In addition, Turkey imported 4.99bn cm in 2003, while the UK and Netherlands are likely to join the LNG importers in the next few years.

France

For many years France was the number one importer of LNG in Europe. The country pioneered LNG trade with Algeria in the mid-1960s and has contracted LNG supplies continually since that time. Major suppliers of LNG include Algeria and Nigeria. In 2003 France imported 7.2mn tonnes, meeting some 24% of its national consumption.

Two receiving terminals are currently in operation. Montoir-de-Bretagne, near Nantes in Brittany, has a capacity of 3.3mn t/y. Fos-sur-Mer, near Marseilles, has a capacity of 7.3mn t/y. Construction of a third plant at Fos Cavaou on the Mediterranean coast is under way. It will accept LNG from Egypt (in 2005) and Qatar (in 2006) and will ultimately add a further 6mn t/y of capacity by 2008.

Spain

Spain is now the number one importer of LNG into Europe. LNG supplies some 63% of the country's gas consumption and imports have more than tripled since 1990. Spain is also the most diversified purchaser of LNG, receiving gas from nine exporting countries. In 2003 it imported 10.98mn tonnes. The major supply contracts are with Algeria, Nigeria and Trinidad. Smaller volumes are imported from Libya, the UAE, Oman, Qatar, Australia and Brunei.

Spain currently has four receiving terminals, with a further three under construction. The national gas supply company, Enagas, operates three of these terminals – located at Barcelona, Huelva and Cartagena – with an aggregate capacity of 10.3mn t/y. The fourth facility, in Bilbao – operated by a consortium of BP, Iberdrola, Repsol YPF and EVE – received its first LNG shipment from the UAE in August 2003. When fully operational, the terminal will have an annual capacity of 2.7mn t/y and will receive most of its LNG from Trinidad. New supplies from Egypt will be imported from 2005.

Italy

Italy is Europe's third-largest importer of LNG, with some 4.03mn tonnes in 2003 coming from Algeria (~40%) and Nigeria (~60%). LNG provides for 9% of annual demand. The country receives LNG through its terminal at Panigaglia, in the Gulf of Genoa. Enel has a 25-year supply contract with Algeria that runs until 2015. Imports to Panigaglia exceeded 4mn tonnes in 2003.

New terminal construction is ongoing at two sites. Edison has begun work on a $600mn LNG regasification terminal on the coast in the Adriatic Sea, to begin operations in June 2005. The project is linked to approval for an onshore pipeline to bring gas to the northeastern part of the country. The terminal will be supplied with 3.4mn t/y from Qatar's RasGas LNG facility. At Brindisi, in southeast Italy, a new terminal is being constructed to accept LNG from Egypt, commencing in 2007. Capacity will be designed to accept 6mn t/y, rising to 9mn t/y on final completion.

Belgium

Belgium's sole receiving terminal at Zeebrugge received 2.29mn t/y of LNG, mostly from Algeria, in 2003. LNG met 18% of national demand. The terminal is operated by Fluxys LNG, with most of the capacity contracted to Distrigas. The

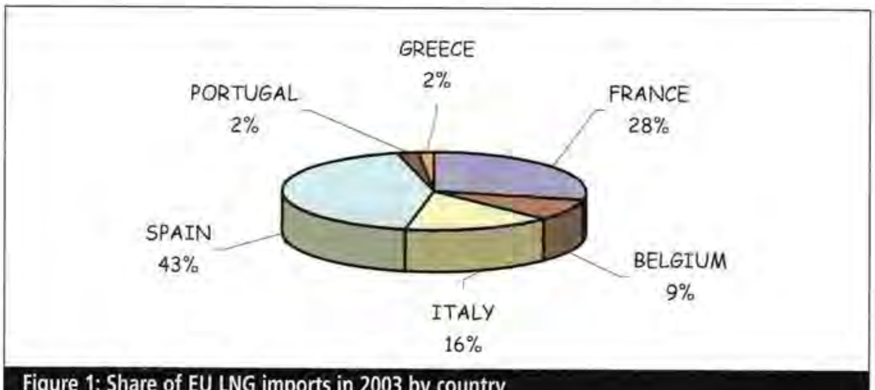

Figure 1: Share of EU LNG imports in 2003 by country

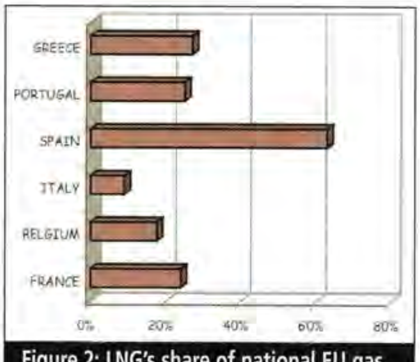

Figure 2: LNG's share of national EU gas markets in 2003

capacity of the terminal is in the process of being doubled by 2007.

Greece
Greece began importing LNG in 2000, under a 21-year contractual agreement with Algeria. In 2003 it imported 0.4mn tonnes. LNG met 27% of national demand that year. Greece's sole LNG terminal at Revithoussa, near Athens, has a capacity of 2mn t/y.

Portugal
Portugal began receiving LNG in 2002, under a 20-year contract with Nigeria LNG. The LNG was initially regasified in Spain and piped into Portugal until October 2003, when the Sines terminal went online. The Sines plant has a capacity of 3.3mn t/y.

UK
The UK pioneered commercial LNG trade with Algeria in 1964. A regasification terminal was constructed at Canvey Island, east of London. LNG was imported in tankers with small capacities of 12,000 tonnes, which shuttled 58 cargoes annually between Algeria and the UK. The latter's gas demand in the early 1960s was 1bn cm/y and LNG supplied 10% of that demand. The 15-year supply contract from Algeria lapsed in 1979 and the Canvey Island terminal was decommissioned in the 1980s.

However, once again the UK is about to become a net gas importer. As part of its medium-term security of supply strategy it is in the process of developing three LNG receiving terminals – one sited near London and two in Milford Haven, West Wales. Transco's Isle of Grain site, east of London, will have a receiving capacity of 4bn cm/y and a storage capacity of 200,000 cm, with start-up scheduled in 2005.

The Petroplus/BG/Petronas Dragon terminal at Milford Haven will have a receiving capacity of 6bn cm/y, a storage capacity of 330,000 cm and start-up scheduled for 2006. Centrica announced in August 2004 a 15-year contract with Petronas to import 3bn cm/y of LNG through the Dragon facility. A further site at Milford Haven's Herbranston terminal will be operated by ExxonMobil/Qatar Petroleum. Receiving capacity will be developed in two phases up to 20bn cm/y, with start-up staggered between 2006 and 2008. The two Milford Haven sites are located on decommissioned refineries where construction is yet to commence. These strategic locations will provide valuable supply to the western demand centres of the UK independently of the main pipeline and storage network focused on the North Sea coast.

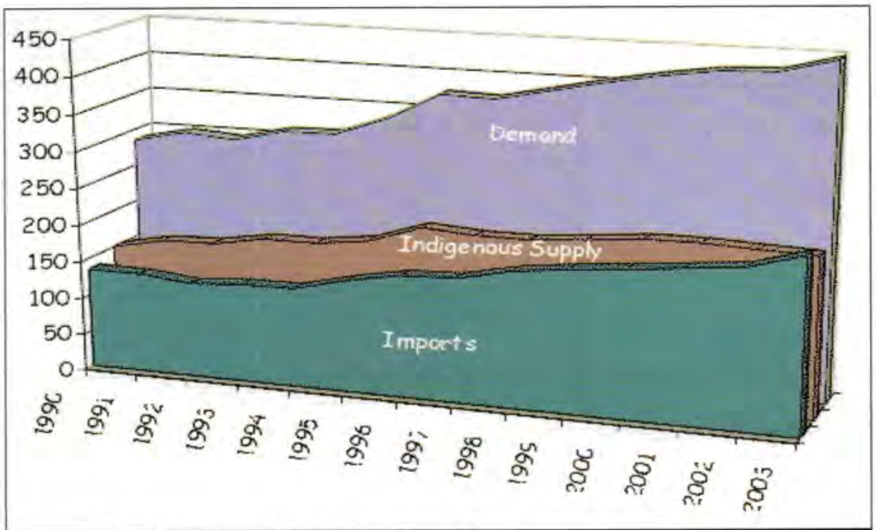

Figure 3: Gas demand, supply and import trends for EU

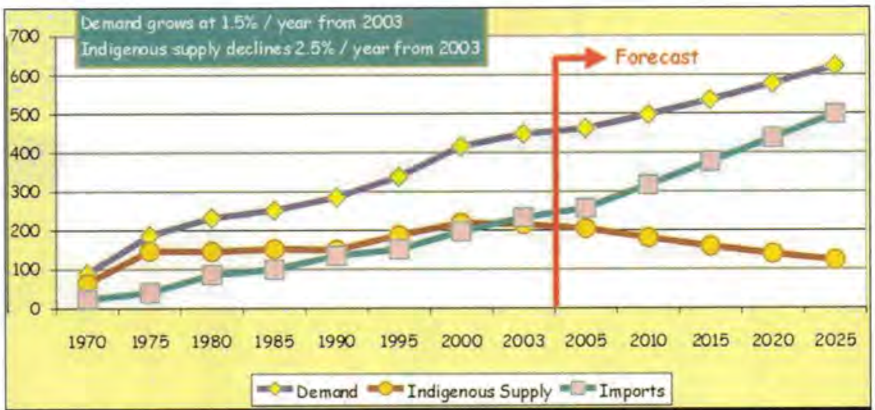

Figure 4: Gas demand, supply and import trends for EU, including modest growth for gas imports from 2003 to 2025

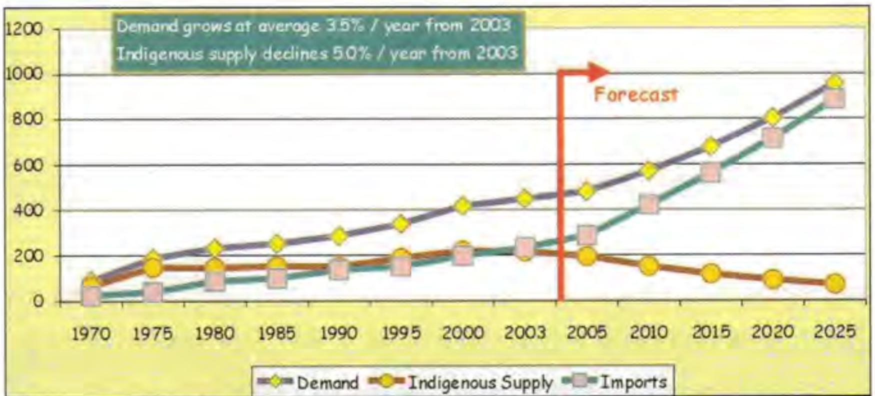

Figure 5: Gas demand, supply and import trends for EU, including high growth for gas imports from 2003 to 2025

The Netherlands
The Netherlands is currently evaluating the feasibility of an LNG import terminal at Eemshaven to bolster its long-term gas supply needs.

LNG suppliers to Europe

Some eight countries – Algeria, Nigeria, Qatar, Libya, Oman, Abu Dhabi, Trinidad & Tobago, and Australia (listed here in order of volumes supplied) – shipped 26.2mn tonnes (34.98bn cm) of LNG to Europe in 2003, representing 20.7% of global LNG trade of 126.4mn tonnes (168.84bn cm). These countries supplied an additional 4.99bn cm to Turkey in 2003.

Many of these existing LNG suppliers are in the process of expanding their

Country of Supply	2003 Total Gas	2010 Total Gas	2010 %	2010 LNG Component	2020 Total Gas	2020 %	2020 LNG Component
Russia	107.6	140	39%	0	170	37%	5
Norway	68.4	90	25%	3	100	22%	5
Algeria	53.2	75	21%	30	90	20%	40
Nigeria	9.2	15	4%	15	15	3%	15
Egypt	0.0	12	3%	12	25	5%	15
Qatar	1.9	10	3%	10	15	3%	15
Libya	0.8	11	3%	1	35	8%	10
Oman	0.3	0	0%	0	0	0%	0
UAE	0.2	0	0%	0	0	0%	0
Other Atlantic Basin	0.1	2	1%	2	5	1%	5
Other Pacific Basin	0.1	0	0%	0	0	0%	0
Totals	242	355		73	455		110
LNG % of Total Gas	14.5%			20.6%			24.2%
EU25 Gas Demand Forecasts (see Table 2)							
Low Growth		280			349		
Mid-Case Growth		317			437		
High Growth		420			714		
Additional Gas Required to Supply High EU25 Gas Demand Growth Scenario							
Azerbaijan	0	15		0	30		0
Turkmenistan	0	10		0	50		0
Iran	0	0		0	30		0
Iraq	0	10		0	20		0
Shortfall from Russia	0	30		0	129		0
High Growth Totals	242	420			714		

Table 1: Gas supply forecasts to EU25 for 2010 and 2020

Country	Gas Balance for EU15, EU25 and EU30: 2003 Total Gas Consumption	2003 Total Gas Production	2003 Pipeline Gas Imports	2003 Pipeline Gas Exports	2003 Net Gas Pipeline Imports	Gas Imports from Non-EU: 2003 Pipeline	2003 LNG	Actual 2003 Pipeline +LNG	Forecast 2010 Low Pipeline +LNG	Forecast 2010 Mid Pipeline +LNG	Forecast 2010 High Pipeline +LNG
Germany	85.5	17.7	86.8	10.3	76.4	59.6	0.0	59.6	65	74	90
Italy	71.7	13.7	55.9	0.0	55.9	48.2	5.5	53.7	58	64	78
France	43.8	0.0	31.8	0.8	31.0	23.0	9.9	32.9	36	40	46
Spain	23.8	0.0	8.7	0.0	8.7	8.7	15.0	23.7	26	30	40
Belgium & Lux	16.0	0.0	14.7	1.6	13.1	5.9	3.2	9.0	11	12	20
UK	95.3	102.7	7.5	15.2	-7.7	6.6	0.0	6.6	15	20	35
Austria	8.6	0.0	7.4	0.4	7.0	6.5	0.0	6.5	8	8	10
Finland	4.5	0.0	4.8	0.0	4.8	4.8	0.0	4.8	5	6	7
Netherlands	39.3	58.3	12.9	42.2	-29.2	4.3	0.0	4.3	5	6	15
Rep of Ireland	4.1	0.0	3.7	0.0	3.7	3.7	0.0	3.7	4	4	6
Portugal	3.0	0.0	2.5	0.0	2.5	2.5	0.9	3.4	4	5	6
Greece	2.3	0.0	1.5	0.0	1.5	1.5	0.6	2.1	3	3	4
Denmark	5.2	7.9	0.0	3.6	-3.6	0.0	0.0	0.0	0	0	1
Sweden	0.8	0.0	1.3	0.0	1.3	0.0	0.0	0.0	0	0	2
Total EU15	403.9	200.3	239.5	74.0	165.4	175.3	35.0	210.3	240	272	360
Czech Rep	9.0	0.0	9.7	0.0	9.7	9.7	0.0	9.7	11	12	15
Hungary	13.0	0.0	10.3	0.0	10.3	8.8	0.0	8.8	10	11	15
Poland	12.5	4.0	8.6	0.0	8.6	8.6	0.0	8.6	10	11	15
Slovakia	7.1	0.0	7.3	0.0	7.3	7.3	0.0	7.3	8	9	12
Slovenia	0.0	0.0	1.1	0.0	1.1	1.1	0.0	1.1	2	2	3
Sub-total E EU	41.6	4.0	37.0	0.0	37.0	35.6	0.0	35.6	41	45	60
Sub-total "EU25"	445.5	204.3	276.5	74.0	202.5	210.8	35.0	245.8	280	317	420
Turkey	21.0	0.0	16.2	0.0	16.2	16.2	5.0	21.2	24	28	32
Romania	18.4	12.6	5.8	0.0	5.8	5.3	0.0	5.3	6	8	10
Bulgaria	2.9	0.0	2.8	0.0	2.8	2.8	0.0	2.8	4	5	6
Switzerland	2.9	0.0	2.9	0.0	2.9	0.4	0.0	0.4	1	2	2
Norway	4.3	73.4	0.0	68.4	-68.4	0.0	0.0	0.0	0	0	0
Sub-total	49.5	86.0	27.7	68.4	-40.7	24.6	5.0	29.6	34	43	50
Sub-total EU30	495.0	290.3	304.2	142.4	161.8	235.5	40.0	275.5	314	359	470

Table 2: 2003 gas balances and 2010 non-EU import demand forecasts for European countries and EU groupings.[7] Countries within EU groupings are ranked in descending order of non-EU gas imports in 2003.[8]

liquefaction capacity, most notably Algeria (despite its setback with the Skikda accident in January 2004), Libya, Nigeria, Qatar and Trinidad. The total liquefaction capacity of Europe's eight traditional LNG supply countries therefore seems set to expand by some 77%, to approximately 178bn cm of gas, by 2008. They are developing much of this additional liquefaction capacity primarily to service other markets – in particular the US and China – but will also face additional competition to supply European markets from new suppliers.

For example, Egypt and Norway have liquefaction plants at an advanced stage of construction, while Angola and Equatorial Guinea seem set to sanction projects to build their first liquefaction plants. These four countries will be looking to market at least some LNG to Europe. Meanwhile, Brazil, Iran, Russia, Venezuela and Yemen also have ambitions to become LNG suppliers – although their focus is more on non-European markets. The giant South Pars gas field development projects involving LNG have progressed slowly after much delay in Iran, but once operational will also be looking for opportunities to market some LNG to European customers.

Details of the liquefaction capacities and development of existing and potential LNG suppliers to Europe are beyond the scope of this article, but are provided elsewhere.[1] An important question is: 'Can Europe's demand growth for LNG sustain such massive growth in supply?' The answer is probably 'No', particularly when competing supplies from additional pipeline capacity are taken into account. The new projects that enter the market earliest are likely to be successful, resulting in delays/postponements to the development schedules of the latecomers.

Gaps in future gas supply

Gas demand from the EU25 countries[2] reached some 449bn cm in 2003, having grown from 285bn cm in 1990 and averaging an annual growth rate of 3.6%/y over that 13-year period.[3] That growth rate in gas consumption had slowed to average 2.5%/y since 2000, but from 2002 to 2003 consumption growth increased again to 4.6%/y.

How demand will grow is open to speculation and forecasts from a range of analysts vary from less than 2%/y to greater than 4%/y on average to 2025. Analysis of individual country growth trends and energy strategies suggest to us that growth in EU25 gas consumption during this period will lie between 1.5%/y (622bn cm by 2025) and 3.5%/y (956bn cm by 2025), depending upon the range of factors influencing market development outlined above. If EU25 gas consumption were to reach 1,000bn cm/y in 2025 this would represent a 3.7% average annual growth rate from 2003.

As part of the overall gas demand growth, LNG supply to the EU increased from 18.7bn cm in 1996 to 35bn cm in 2004 (14.5% of all gas imports) at annual rate of 9.4% (or 9.6% if Turkey is included).[4] This growth rate is 50% higher than the growth in global LNG demand over the same period. This represents three times the average annual growth in overall gas demand. If LNG imports to the EU25 grow at an average rate of 10%/y from 2003 to 2025, annual LNG imports would amount to 285bn cm (some 30% to 45% of our total EU gas demand forecast). Based upon the planned LNG projects due to come onstream by 2008, a 5%/y average growth forecast to 2025 seems pessimistic, but would raise EU_{25} LNG imports to 102bn cm. These two growth rates will probably bracket the growth in LNG imports that materialises over that 22-year period.[5]

The supply gap to be filled by gas imports in the period up to 2025 depends not only upon demand growth but also on how indigenous supply declines. **Figures 3, 4** and **5** illustrate the historical and future forecast gas supply, demand and import positions on which Europe's potential gas supply gap is based. The rapid increase in gas imports in 2003 (**Figure 3** – 10%) is perhaps a foretaste of the short-term trends. Our mid-case import growth forecast (**Figure 4**) leads to 437bn cm of imports by 2020. This is similar to DG Tren's low case forecast of 410bn cm by 2020.[6] However, our high import growth forecast (**Figure 5**) predicts imports of 714bn cm in 2020 compared to 542bn cm for the DG Tren high case forecast. Our high case assumes combined rapid demand growth with steep decline of indigenous supply.

We have also developed a low growth case (see **Tables 1** and **2**), which involves 1% growth in demand and 1% decline in indigenous supply, and results in an import requirement of just 349bn cm in 2020. If such a forecast materialised almost no new gas supply projects sanctioned after 2005 would be required.

Details of our low, mid-case and high import forecasts for years 2010 and 2020 and a country by country breakdown of how we see supply distributed are given in **Table 1**. How gas demand might develop in specific countries if demand lies between our mid-case and high growth forecasts is indicated in **Table 2**.

The 2010 country forecasts in **Tables 1** and **2** are in line with projects sanctioned in 2004 and suggest that if only mid-case import growth materialises then there is likely to be a supply glut (ie 355bn cm supply versus 317bn cm demand for EU_{25}). The LNG component of supply in any event is likely to rise to between 20% and 25% of total gas imports. On the other hand, if high import growth materialises, by 2010 there is likely to be a supply shortfall, and imports from Central Asia, Iraq and Iran, plus additional supply from Russia, would be required to meet demand. Our forecasts suggest the EU_{25} diversifies its supply with the percentage contribution from Russia falling below 40%. However, Russia remains the dominant supplier and in the high import growth case it becomes the key swing producer, increasing its market share to meet supply shortfalls.

Significant development of gas supply by pipelines from the Central Asian Republics, Iran and Iraq is only required to meet the high import growth case. If this materialises then the geopolitical importance of these countries to the EU_{25} is significant, along with the Turkish gateway to Europe for their gas. Although this outcome is only a possibility, it seems prudent that the EU should address the geopolitical issues of Russian and Iranian control over movements of Central Asian gas by supporting the establishment of direct import routes through Turkey (ie Trans-Caspian route) in the next five to ten years if a potential EU gas supply crisis, with over-dependence on Russian gas in the period 2010 to 2020, is to be avoided.

Conclusions

The period 2007 to 2010, when major new LNG and pipeline gas projects are scheduled for completion, will be a critical period in gas-to-gas competition. Gas supply from the new development projects is chasing finite gas demand in Europe. Those projects that manage to underpin their operations with long-term contracts early in this period will have the best chance of achieving sustained economic success. Traditional linear gas supply chains to Europe are likely to evolve into networks and ultimately into a complex supply web by 2020 integrating both pipeline and LNG gas sources.

The pace of expansion of the European gas market is subject to risk and uncertainty. It will depend on commitments to large capital investments and the continued pull from the power sector. Such commitments themselves depend upon the EU's ability to agree and successfully implement strategy, internal political wrangling over energy mix (eg nuclear, renewables versus gas) and, in the case of pipeline supplies, overcoming some significant external geopolitical hurdles involving Russia, the Central Asian Republics, Iran, Saudi Arabia and Turkey.

The very large investments required to create gas supply infrastructure (both LNG and pipeline) will continue to be supported by long-term purchase agreements, with share price and volume risks between sellers and buyers. However, as a more integrated and complex web of gas supply evolves in Europe, short-term trading, spot markets and contractual flexibility will undoubtedly grow and exert more influence on regional prices.

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Footnotes

1. Pyke & Wood, *LNG Journal*, Nov/Dec 2004, p9–24.
2. The 25 countries that make up the European Union from 2004. EU country groupings commonly used for energy supply and demand analysis are shown below.

States Making Up European Union			
	2003	2004	Future?
Grouping	EU15	EU25	EU30
1	Austria	Austria	Austria
2	Belgium	Belgium	Belgium
3	Denmark	Cyprus	Bulgaria
4	Finland	Czech Rep	Cyprus
5	France	Denmark	Czech Rep
6	Germany	Estonia	Denmark
7	Greece	Finland	Estonia
8	Ireland (Rep)	France	Finland
9	Italy	Germany	France
10	Luxembourg	Greece	Germany
11	Netherlands	Hungary	Greece
12	Portugal	Ireland (Rep)	Hungary
13	Spain	Italy	Ireland (Rep)
14	Sweden	Latvia	Italy
15	United Kingdom	Lithuania	Latvia
16		Luxembourg	Lithuania
17		Malta	Luxembourg
18		Netherlands	Malta
19		Poland	Netherlands
20		Portugal	Norway
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24		Sweden	Slovakia
25		United Kingdom	Slovenia
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27			Sweden
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29			Turkey
30			United Kingdom

3. *BP Statistical Review*, June 2004.
4. Ibid.
5. See David Wood, *Petroleum Review*, February 2004, p38, for detailed discussion of growth in global LNG market.
6. *European Energy and Transport Trends to 2030*, European Commission Directorate-General for Energy and Transport (DG Tren), January 2003.
7. Some of the smaller EU_{25} member states (eg Cyprus, Malta and Baltic States) are omitted from **Table 2** on the basis that gas consumption and import potential are small.
8. Note that the 2003 actual EU_{25} non-EU gas import volume of 245bn cm quoted in **Table 1** is higher than 242bn cm supply volume quoted in **Table 1**. This is due to re-export to non-EU_{25} countries of small volumes of gas not accounted for in **Table 1**. Both sets of figures come from *BP Statistical Review*, June 2004.

Remote-controlled mud tank cleaning improves safety

Total Reclaim Systems (TRS), a leading provider of mud tank cleaning services, has introduced PitGun – an innovative system that cleans and removes waste material from mud tanks remotely. This means that operators and rig owners are no longer required to have personnel enter mud pits or tanks to manually break up compacted solids that inevitably build up on the floor, beneath pipework, and in tank corners during the drilling process.

For its inaugural job, TRS successfully used the PitGun to carry out a mud tank cleaning and waste removal operation on behalf of Marathon on the Brae 'A' platform in the North Sea. Plans for additional cleaning service operations are already scheduled to take place throughout the coming months.

A single operator manipulates the PitGun's cleaning jets remotely while standing outside of the tank. The volume, pressure and direction of the specially designed jet nozzles are easily controlled, making it simple to concentrate on cleaning problematic areas, including solids build-up and beneath pipework. With the PitGun's floor-orientated jet head, difficult areas can be cleaned without entering the tank.

Because TRS has incorporated its field-proven Reclaim pump unit to drive the system, the PitGun is said to be self-sufficient and operates without tying up the rig's pumping system, requiring only rig air or electricity to operate. The PitGun, which is quickly rigged and de-rigged, is lightweight, portable and can be operated either by rig-crew or service company personnel.

One of the primary challenges that TRS faced while designing the PitGun was to develop a system that would minimise the volume of waste fluid required to clean. This has been made possible by recovering the residual 'dead volume' of oil-based mud (OBM) via the Reclaim pump's high vertical suction capability. This fluid is then jetted through the pump and the specially designed nozzles. By doing so, solids are displaced from the pit walls, while any remaining solids on the tank floor are slurrified. The operator then uses the PitGun to direct the remaining slurry to special portable vacuum drum strainers that remove the waste material to a tote-tank, consolidation pit or vessel for removal. The operator finishes the job by thoroughly cleaning the tank interior with the PitGun. Cleaning fluid comprised of seawater and detergent is used, which may then be re-circulated and recovered by the Reclaim pump unit to further reduce the volume of waste material.

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Protecting primary fire equipment

In a move to provide safer, more easily identifiable and robust storage for primary firefighting equipment, Jo Bird & Co has launched a new ToughStore cabinet range. There are four cabinets in the range. The TS101 (red) provides storage for a single fire extinguisher; the TS201 (red) holds two fire extinguishers and the TS11 (red) stores one 20-metre firehose and branchpipe. Completing the range is the TS200BA (green), which is designed to store one set of breathing apparatus for emergency use. Variants are also available to store helmets, axes and other first line of defence firefighting equipment.

For the first time new materials have been used to mould the cabinet to afford a combination of high visibility, impact resistance and security. The cabinets, except the TS11, are manufactured from high strength ABS and have clear polycarbonate doors which not only provide high impact resistance but afford easy identification of the contents both in emergencies and in routine checks. High performance seals and hinges provide extra durability. The TS11 is moulded from medium density polyethylene (MDPE) and incorporates an opaque cabinet and door with high performance seal and hinges.

The TS101, TS201 and TS200BA have a security seal incorporated in the handle to allow visual checking for evidence of tampering and can be fitted with an optional audible alarm which is set off when the cabinet door is opened. This provides a further deterrent to misuse or abuse and alerts others in the vicinity of the potential dangers of a fire outbreak.

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Heavy duty 'big brother' unveiled

The heavy-duty 'big brother' to conventional strut framing systems, Halifen's Powerclick 63 system is designed to cater for pipes of up to 150 mm nominal diameter and is claimed to offer considerable benefits in ease, speed and final cost of installation compared to alternative welded assemblies used in the offshore oil industry.

Using a minimum of components that are all available ex-stock, Powerclick 63 provides an off-the-shelf solution to what has been until now a custom-designed and built market.

According to Halifen, the heavy-duty framing eliminates the need for time-consuming and costly detailed planning of pipework support structures, reduces days of welding assemblies together to just a few hours of bolting together pre-assembled components, and enables alterations to existing pipework layouts to be achieved quickly, easily and economically.

Fundamental to the system's flexibility is a box-section channel that incorporates a toothed channel, to give great torsional strength and safe load distribution. The channel, which is assembled by means of connectors, accepts rapid assembly captive bolts for the fixing of pipe clamps and other accessories. The components are supplied pre-assembled to make construction of framing simple and easy.

t: +44 (0)8705 316300
f: +44 (0)8705 316304
www.halfen-powerclick.com

Low-cost, flexible coupling for pump drives

Centa Transmissions has launched a new low-cost, flexible coupling specifically designed for electric motor and hydraulic pump drives. The Centaflex Series C coupling has two metal hubs and a polyurethane elastomeric element that is resistant to heat, oils, chemical agents and ozone, making it ideal for applications in a chemical or corrosive environment.

The couplings are also said to be resistant to ageing and hydrolysis, possess high internal damping capabilities and will operate in temperatures ranging from –40C to +100C.

t: +44 (0)1274 531034
www.centa.info

New oil and grease/TPH method

The measurement of total oil and grease (TOG) and total petroleum hydrocarbons (TPH) in water is important not only in pollution monitoring but also in site remediation and the determination of recoverable oils in recycling.

'The use of freon has been banned under the Montreal Protocol, so the ASTM's new method D 7066-04 using the environmentally acceptable S-316 solvent (a dimer/trimer of chlorotrifluoroethylene) as an extraction solvent will be welcomed,' comments Quantitech.

'The new method follows the S-316 extraction by measurement of infra-red absorption at 3.4 microns in a fixed-wavelength infra-red analyser such as the Wilks Infracal Model CVH,' comments Quantitech, the UK distributor of the analyser.

'The Infracal CVH was one of the instruments used in the development of the new method, and can determine TOG and TPH levels down to 1–2 ppm in 10–15 minutes, including extraction.'

The scope of ASTM D 7066-04 is up to 100 ppm, but the Infracal CVH is reportedly able to give reliable measurements to well over 500 ppm.

The instrument is said to be extremely portable, weighing under 5 lbs, and easy to use – making it ideal for onsite measurements.

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www.quantitech.co.uk

Spill Awareness and Control*

(Fosse Liquitrol, Whetstone Magna, Lutterworth Road, Whetstone, Leicestershire LE8 6NB, UK. t: +44 (0)870 224 7841; f: +44 (0)870 224 7842; e: sales@fosse.co.uk*;* www.fosseliquitrol.com*). Price: £79.50. Running time: 23 mintues.*

Containing detailed information that is up to date with UK environmental legislation on spill prevention and control, this video has been compiled to support a spill control training course, inform and educate new employees and provide refresher information. It supports the roles of the First Responder, Supervisor, Engineer and Health & Safety Manager, who have a responsibility for safe working procedures and emergency response strategies. The video contains a wealth of information on the risks associated with non-compliant and poorly-practised spill control and clearly identifies strategies and procedures to prevent unnecessary spills and what to do if they occur.

Motor Vehicle Emission Regulations and Fuel Specifications – Part 1: 2002/2003 Update*

(Concawe, Boulevard du Souverain 165, B-1160 Brussels, Belgium. t: +32 2 566 91 60; f: +32 2 566 91 81; e: info@concawe.be*). Available as free download from* www.concawe.be

This report summarises changes in worldwide legislation and regulations governing motor vehicle emissions, fuel specifications and fuel consumption. Specifically, it details current and proposed legislation on emissions limits and emissions testing, vehicle inspection and maintenance programmes, plus legislation aimed at controlling in-service emissions performance, fuel consumption and carbon dioxide emissions. It also includes information on fuel specifications and characteristics. The report should be read in conjunction with Part 2, which was originally issued as a separate volume in 1997. It is intended that Part 1 will be updated regularly, whereas Part 2 – a comprehensive reference document – will be revised at longer term intervals.

High Noon for Natural Gas: The New Energy Crisis*

Julian Darley (Chelsea Green Publishing, PO Box 428, White River Junction, VT 05001, US. t: +1 802 295 6300; www.chelseagreen.com*). ISBN 1 931498 53 9. Price: $18 (paperback); $30 (hardback).*

This publication takes a close look at natural gas as an energy source that rapidly went from nuisance to crunch. It outlines the implications of our increased dependence on this energy source and why it has the potential to cause serious environmental, political and economic consequences.

Tanker Bills of Lading: A Practical Guide*

(Intertanko, Bogstadvein 27B, PO Box 5804 Majorstuen, 0308 Oslo, Norway. t: +47 22 12 26 40; f: +47 22 12 26 41; e: oslo@intertanko.com*;* www.intertanko.com*). Price: $100 (Intertanko members); $150 (non-members).*

This guide describes both law and practice regarding tanker bill of lading, including analysis and explanation of terms used in shipping and banking practice. It seeks to deal clearly and concisely with some of the common misconceptions and problems that can be encountered with such documents. The publication is complementary to the Intertanko publication – *A Guide to Tanker Charters*.

Standard Handbook of Petroleum & Natural Gas Engineering*

William C Lyons and Gary J Plisga (Gulf Professional – an imprint of Elsevier, Linacre House, Jordan Hill, Oxford OX2 8DP, UK. t: +44 (0)1865 843848; www.elsevier.com*). ISBN 0 7506 7785 6. Price: £89.99 (hardback).*

Now in its second edition this book provides a comprehensive source of petroleum and gas engineering information in an easy-to-use single volume. It includes thousands of illustrations and 1,600 information-packed pages on the newest developments, advances and procedures in the petrochemical industry, covering everything from drilling and production to the economics of the oil patch. The books also features a range of calculations, tables and equations that engineers need on the rig or in the office.

New stock in EI Library

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- *European downstream oil industry safety performance. Statistical summary of reported incidents – 2002.* CONCAWE, Brussels, April 2004.
- *High noon for natural gas: The new energy crisis.* Darley, Julian. Chelsea Green Publishing Company, White River Junction, Vermont, US, 2004. ISBN 1931498539.
- *Kizomba A: Foundation for the future – Deepwater success in Angola Block 15.* Pennwell Custom Publishing, Tulsa, Oklahoma, US, November 2004.
- *Standard handbook of petroleum & natural gas engineering.* Lyons, William C (ed.); Plisga, Gary J, (ed.) 2nd edition. Gulf Professional Publishing Elsevier, Burlington, Maryland, US, 2005. ISBN 0750677856.
- *Tanker bill of landing: A practical guide.* International Association of Tanker Owners (Intertanko). 1st edition. Intertanko, London, UK, September 2004.
- *World energy outlook 2004.* International Energy Agency (IEA), Paris, France, October 2004. ISBN 9264108173.

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This course is designed for a multi-disciplined audience with diverse corporate, financial, technical, strategic planning, risk management and operational backgrounds. Course content addresses issues and skills relevant to professionals working within listed and state-owned oil and gas companies and many support and service sectors to the industry, including: accountants, analysts, asset managers, auditors, bankers, economists, insurers, lawyers, portfolio analysts and managers, public relations managers and consultants.

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This course is designed for a multi-disciplined audience with diverse commercial, technical, corporate, operations, planning and risk management backgrounds from various sectors of gas and power supply chains. Course content addresses issues and skills relevant to professionals working within companies producing, trading and marketing gas and the many service sectors supporting the industry, including: analysts, asset and portfolio managers, bankers, economists, engineers, gas traders, geologists, insurers, lawyers and risk managers.

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