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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover: Top: IP Award winners and sponsors take to the stage at the Savoy Hotel, London. *Photo: Jim Four.* Left: Shell's Electric Storm on the South Bank, London, UK (see p40). *Photo: courtesy of Shell.*

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ROUNDUP From the Editor

Bumper years for oil mega projects

Petroleum Review would like to start by thanking readers and contributors for all their help and support over the year. We would also like to wish our readers an enjoyable festive season and a prosperous 2004.

One of the great pleasures of writing about the international oil and gas industry is that it is never dull. The industry involves everything from high political drama to the most cutting edge of new technology, and all stops in between. This spread of interest is reflected in this issue. On p36 we feature the rapid evolution of the 'digital oil field', which promises to reduce costs and improve recovery to a quite remarkable degree. As usual at the start of new year, we do a quick 'tour de horizon' with articles looking at prospects in the US (p28) and Latin America (p25).

Much has been written about the way the new super majors created by the mergers of the 1990s need mega projects in keeping with the scale of their operations. The oil majors and super majors are increasingly selling their interests in areas of production decline (US lower 48, UKCS, etc) precisely because these small and diminishing flows are no longer material to their operations. These assets are passing into the hands of enthusiastic smaller companies, where company size and production flows are in more comfortable balance. Surprisingly often the new owners are able to bring new thinking and new approaches and to create thriving companies with the final flows of elderly fields.

However, the overall health of the industry is largely driven by the development of the oil mega projects. These provide the big contracts, the large new production flows and, possibly most important of all, justify the building of the infrastructure which become the tomorrow's production hubs. It is the availability of these hubs that allows the development of the smaller accumulations. On p18 we list all the oil mega projects and major oil discoveries that we have been able to identify with a planned production peak of over 100,000 b/d.

Major projects are generally not secrets – companies are usually proud to announce when they give sanction to a new project. Similarly, stock market pressures mean that major discoveries are rarely kept secret for long. Our cut-off for the listing of discoveries is reserves of over 500mn boe or a likely production peak of over 100,000 b/d.

The first, and most notable, feature of the listing is that there are a number of potential mega projects in the Middle East and Russia, for which the go ahead has not yet been given. The second feature is that while the next four years seem set to be fat years for the industry in terms of new flows, the years after 2007 currently look to be rather lean years.

Russian games

Outsiders can only gaze in awe and trepidation as the current Russian administration defines its relationship to the oil industry and the oligarchs. The latest twist in an already convoluted saga is the apparent breakdown of the Yukos /Sibneft merger. Apparently this is at the behest of Ramon Abramovich of Sibneft, and possibly at the behest of Mr Putin. Yukos and Sibneft are apparently quarrelling over who dominates and who has the top jobs. At the time of writing it was unclear whether the merger was on or off.

Equally unclear was whether Russia was on the point of signing or not signing the Kyoto treaty. The Russian signature could bring the Kyoto treaty into effect even without the US signing, although it is not clear how effective it would be in such circumstances. It is hard to avoid the conclusion that various factions in Russia are greatly enjoying the power and limelight their decision on whether the Kyoto treaty lives or dies has given them.

To watch in 2004

Already it is possible to identify a number of key aspects of the industry to be watched closely in 2004. In no particular order:

- The Russian government's relationship with the Russian oil companies. The degree of independence the Russian companies are allowed.
- The way the US gas supply crisis unfolds (at the time of writing the price had just spiked to $6.3mn Btu). Demand destruction/new supply/LNG imports.
- The cohesion of Opec and how it manages the normal second quarter demand decline.
- The speed of economic recovery and its impact on oil and gas demand.
- The progressive impact of electronic enablement in initiatives such as the 'Digital Oilfield'.
- Sales and development of new environmentally friendly fuels

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

eworld

OGLinks.com has undergone a face lift, the re-launched site now offering users quicker links to over 1,000 sites that provide key oil and gas industry information and market data. The home page has hourly updated news headlines, stock market and on-line newspaper links with the latest industry developments. The site also features an extensive listing of energy companies, with direct links to press releases, e-newsletters and over 30 directories for free company listings.

NEL, the technology services organisation, has launched a web-based industrial club to help companies understand the legislative and technology issues related to produced water. Providing access to practical information on produced water treatment, handling and management, the Produced Water Club has received support from DTI and Scottish Enterprise. Ten major operators and service providers have joined the Club so far. For more information, contact Dr Ming Yang on e: **myang@nel.uk**

The Consilience Energy Advisory Group (CEAG) recently unveiled its new website at **www.ceag.org** The site explains the range and scope of the group's energy market consultancy practice and provides access, free of charge, to approximately 100 articles published in the trade press by CEAG on the subject of oil markets, shipping markets, gas markets, power markets, emissions markets and weather markets

The UK Health and Safety Executive (HSE) has published four approved codes of practice (ACOPs) supporting the Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR). The ACOPs are intended to help employers eliminate or reduce fire and explosion risks from dangerous substances. The subjects covered are: design of plant, equipment and workplaces; storage of dangerous substances; control and mitigation measures; and safe maintenance, repair and cleaning procedures. The ACOPs contain updated good practice and effectively replace existing safety legislation on flammable and explosive substances that DSEAR revoked earlier this year. A fifth and overarching ACOP on DSEAR is due to be published in December 2003. General information on DSEAR can be found on the HSE website at **www.hse.gov.uk/spd/dsear.htm**

Radar Energy, a Houston-based energy consultancy, is accepting nominations for its '50 Key Women in Energy – Global' honours programme. Nomination forms can be downloaded from **www.keywomeninenergy.com**

In Brief

UK

Tullow Oil has completed the £5.2mn *purchase from Eni UK of its 23.33% equity in the Thames gas fields and the associated licence interest, P037, in North Sea block 49/28. Tullow now has a 66.66% interest in Thames.*

Tullow Oil has completed the $8.3mn *sale to Viking Petroleum UK of its remaining UK onshore interests, principally comprising a 60% equity in the North Yorkshire gas fields and operatorship of the Knapton power station on behalf of ScottishPower.*

JP Morgan has been appointed by *Intrepid Energy to act as exclusive agent in the sale of the company. Intrepid is one of the largest independent oil and gas companies in the North Sea to become available for acquisition in recent years and includes a 30% stake in the Buzzard field (see p5).*

Over 4,000 coal-mining jobs in the UK *are to be secured and 300 jobs created as part of a £52mn investment package recently announced by Energy Minister Stephen Timms. Further information about the Coal Investment Aid scheme is available from* **www.dti.gov.uk/energy/coal/investaid/index**

A newly developed low-cost oil and *gas prospecting technology from Shell Global Solutions is claimed to be helping to find oil and gas reserves by measuring ethane gas escaping from the ground. Developed in co-operation with scientists from the Optics Applications Group at the University of Glasgow, LightTouch uses a specially-adapted vehicle fitted with an extremely sensitive ethane gas sensor.*

Dana has completed the acquisition *from Shell Expro and Venture Production of interests in the Kittiwake and Mallard oil fields, neighbouring oil discoveries and exploration licences in the UK central North Sea. Following the deal, Petrofac Facilities Management has taken over responsibility for management of the Kittiwake facility.*

Europe

The open-sea extraction of gas is to *soon begin for the first time in Bulgaria with the 350mn t/y capacity Galata platform, built, installed and commissioned by Petreco of the US at a cost of $700mn.*

NEWS Upstream

Standard contracts cutting costs

Speaking at the launch of three updated standard contracts at a reception in Aberdeen on 12 November 2003, Sir Ian Wood of the John Wood Group and Trevor Garlick of BP stated that standard contracts are already saving the UK oil and gas industry up to £20mn a year, but there is the potential for even greater cost-savings if more companies across the sector were to adopt their use. They argued that widespread use of industry standard contracts speeds up contract awards as their familiarity increases in the supply chain and because they reduce the need for repetitive tender qualifications. Standardisation also creates greater consistency in contracting practice, especially in allocating risk. The net gain for both client and contractor are substantial savings in both legal and administrative costs.

Sir Ian Wood said: 'The use of standard contracts is growing across the UK oil and gas industry and this practice is to be strongly encouraged. The benefits are plain to see, with more and more companies coming to realise how these contracts can positively improve business efficiency. What is more, we are also beginning to see interest from overseas. Wood Group has recently concluded a major five-year contract with Talisman Energy UK valued at some £250mn using one of these industry standards.'

The first standard contracts were first published in 1997 as part of the CRINE efficiency drive and are now being updated to reflect changes in the law and developments in good contracting practice. Today, there are ten standard contracts in circulation, covering Design, Construction, Onshore and Offshore Services, Well Services, Marine Construction, Mobile Drilling Rigs, Supply of Major Plant and Equipment, SME Services and a Purchase Order form.

The three new editions being launched are the contracts for Design, Construction and onshore/offshore Services work. They will shortly be followed by the second edition of the Marine Construction contract. The second edition of the Well Services contract was published in 2001 and work is in hand reviewing the others.

The contracts are managed by the Standard Contracts Committee operating under the auspices of LOGIC, and are supported by PILOT's Progressing Partnership initiative with its Supply Chain Code of Practice, one of whose objectives is to increase their use across the sector. For more information, visit **www.logic-oil.com**

ABS guidance first on deepwater FPUs

Installed in 1996 on Viosca Knoll block 825 in 1,930 ft of water in the Gulf of Mexico, Kerr-McGee's Neptune became the industry's first spar. The classic spar design has led to further emerging technologies, including the truss spar and cell spar innovations. Focused on the continued safe operation of spars and tension leg platforms (TLPs), ABS has announced its industry-first guidance on building and classing the specialised deepwater floating production units.

There are presently some 20 TLPs and some 10 spars installed worldwide, with an estimated 20 new TLPs and another 30 spars expected over the next decade. Of the units installed, ABS has classed 13 of the TLPs and all of the spars, including Neptune.

Norway orders a breath of fresh air

Navion Shipping Company has been awarded a NKr230mn purchase order to equip three shuttle tankers with VOC (volatile organic compounds) emissions recovery systems, writes *Brian Warshaw*. The 130,000 dwt *Navion Hispania* and *Navion Scandia* vessels were built in 1999 and 1998 respectively. The third vessel is the 147,500 dwt *Nordic Stavanger*, which is owned by Ugland Nordic Shipping. Due to enter service later this year, the vessel was built in South Korea by Samsung and will be registered in the Bahamas.

Acting through Statoil, the 25-member VOC industrial partnership has selected the VOC Recycling system manufactured by Hamworthy KSE as the unit to be installed on board the shuttle tankers. Although the recovery system has only been operating at sea since mid-April, it has proved successful at recovering or utilising all the emissions, including the methane and ethane factions that are discharged into the atmosphere in other available commercial systems. VOC Recycling uses conventional liquefaction to convert the heavy factions into condensate, which is stored for off-loading at the terminal. The methane and ethane vapours are retained and burned in the boiler to raise steam for the electrical generators that independently power the recovery system.

It had been predicted that the partnership would require five additional vessels to be equipped with recovery systems to enable them to meet the Phase II requirements of Norwegian legislation which specifies that 70% of offshore VOC emissions must be recovered by the start of 2005. However, the greater efficiency of the VOC Recycling system appears to have influenced the partnership into ordering only three units – although an option has been retained for an additional two units. A total of 11 shuttle tankers equipped with vapour recovery systems will be operating between oil fields on the Norwegian Continental Shelf and onshore terminals by the end of 2004.

Irong Barat B and Raya B brought onstream

ExxonMobil has commenced oil production from Irong Barat B and Raya B, the last two of five satellite platforms installed under the Satellite Fields Development Phase I (SFD I) Project in the South China Sea offshore Malaysia. About 70mn barrels of oil from six fields will be produced from the five satellite platforms, with peak production expected to total about 40,000 b/d.

Since the development of the SFD I Project, the company has installed three additional facilities under the SFD Phase II Project in 2002 at Bintang A and B, and Tapis F. Fabrication of two more platforms is due to start soon under the SFD Phase III Project, planned for installation in 2004.

Lundin buys DNO subsidiaries

Lundin Petroleum has entered into an agreement with DNO to purchase DNO's UK and Irish oil and gas interests, as well as the majority of its Norwegian assets, for $165mn in cash. Lundin's estimate of proven and probable reserves of these assets is approximately 65mn boe. Current production from these assets is in excess of 12,000 boe/d and is expected to increase to in excess of 20,000 boe/d in 2H2004 on production start-up from the Broom field in the UK North Sea.

The sale includes Lundin's purchase of the following DNO wholly-owned subsidiaries:

- DNO Britain Limited, which, through wholly owned subsidiaries, includes the following interests: 100% Heather field, 99% Thistle field and 55% Broom field. The Heather and Thistle fields are mature producing fields in the UK North Sea whilst the Broom field is a newly designated field adjacent to the Heather field and currently under development. The Broom field will be tied back to the Heather facilities, thereby extending the economic life of the Heather field. Lundin Petroleum will assume operatorship of these fields.
- Island Petroleum Developments, which owns a portfolio of assets offshore Ireland. The major asset is a 12.5 % working interest in the Seven Heads gas field operated by Ramco, which is expected to begin production in 4Q2003 using the existing Kinsale Head facilities. IPDL also owns additional exploration and development licence interests offshore Ireland.
- All of the Norwegian assets of DNO with the exception of its interest in the producing Glitne field. The Norwegian assets to be acquired include a 7% working interest in the producing Jotun field operated by ExxonMobil and a 15% interest in PL203 operated by Marathon, which includes existing oil and gas discoveries expected to be developed as part of the West of Heimdal project, as well as various additional exploration assets.

In Brief

The Shell Oil Company and Bord na *Móna are reportedly launching a joint campaign to convince residents in North Mayo that a controversial £150mn gas terminal to treat gas from the offshore Corrib field can be built without damaging the environment. Shell had been refused planning permission by An Bord Pleanála amidst fears that the 600,000 tonnes of excavated peat from the site at Bellanaboy to a Bord na Mona-owned bog ten miles away could not be safely stored on the site. Shell now says that a plan to spread the excavated material on the cutaway bog can resolve this problem.*

Norsk Hydro has awarded a contract *to FMC Kongsberg Subsea for engineering, procurement, construction and testing of the subsea production system for the Ormen Lange gas field, as well as options for further equipment deliveries. The contract is valued at NKr1bn.*

Allseas Marine Contractors has secured *a NKr85mn contract to lay the gas pipeline from Statoil's Visund development in the North Sea to the Kvitebjørn gas pipeline.*

It has been reported that up to six new *oil finds may lie in the Norwegian Sea between the islands of Roest and Vesteralen. However, environmentalists are understood to dispute the estimated NKr700bn value of the oil and have warned of potential ecological damage should exploration operations be given the go ahead.*

The Ormen Lange licence group has *awarded pipeline installation contracts to Stolt Offshore and Allseas Marine Contractors – valued, respectively, at approximately NKr2bn and NKr1.5bn, including options. The Ormen Lange export pipeline system will be the world's longest subsea pipeline, with a total length of about 1,200 km.*

North America

EnCana is now expanding coalbed *methane (CBM) development on its 700,000 acres of 100% owned royalty-free lands in southern Alberta – resource play type properties that are estimated to contain more than 2tn cf of recoverable natural gas resources from coal. Over the next five years, EnCana expects to increase natural gas production from coal seams to more than 200mn cf/d.*

In Brief

Unocal has discovered gas on Alaska's *Kenai Peninsula. The Happy Valley prospect is estimated to hold between 75bn and 100bn cf of gas. The field is due onstream in autumn 2004, targeting daily production of up to 25mn cf/d in 2005.*

The US Minerals Management Service *(MMS) is reportedly planning to offer 2mn acres in Alaska's Cook Inlet for oil and gas leasing in mid-2004. The May sale is expected to include a number of financial incentives to attract bids, including an extension of the lease period from five to eight years and a suspension of federal royalties on up to the first 30mn boe produced from any discoveries.*

Total has announced the start-up of its *Matterhorn field in Mississippi Canyon block 243 in the deepwater US Gulf of Mexico. The field has been developed via a tension leg platform (TLP) with a throughput capacity of 33,000 b/d of oil and 55mn cf/d of gas.*

BHP Billiton reports that its first *appraisal well on the Shenzi field in the Gulf of Mexico Green Canyon block has encountered approximately 500 ft of net oil pay.*

Anadarko, Dominion Exploration & Production and Spinnaker Exploration *have announced a deepwater discovery on their Spiderman prospect on DeSoto Canyon block 621 in the Eastern Gulf of Mexico. The discovery well was drilled in 8,100 ft of water and encountered more than 140 ft of net pay in its two primary targets. Spiderman is expected to be tied back as a satellite to a hub production facility. A central hub could service a large area, including Anadarko's Atlas and Jubilee discoveries.*

Middle East

Tatneft is reported to have won a *tender to explore and develop oil fields in Syria.*

South Korea's Export-Import (Exim) *Bank is understood to have extended a $880mn loan to LG Engineering and Construction to fund development of Phases 9 and 10 of Iran's South Pars gas field. Estimated reserves are 463tn cf of gas and 600mn tonnes of condensate.*

Kuwait's Energy Minister is understood *to have said that the Emirate could take a dispute with neighbouring Iran over*

NEWS Upstream

Surmont heavy oil project to move ahead

ConocoPhillips (43.5%; operator) has announced that, together with partners Total (43.5%) and Devon (13%), it plans to move ahead with a $1.43bn heavy oil project in Northern Alberta. The company is to use steam assisted gravity drainage (SAGD) technology to produce heavy oil from its Surmont leases starting in 2006, with peak production of 100,000 b/d expected in 2012.

Peter Hunt, a spokesman for ConocoPhillips, said the company's Board decided to give the project the go ahead after Canada's oil and gas industry received assurances from Ottawa that its decision to ratify the Kyoto Protocol on climate change would not affect the project's sustainability. After a thorough review, he said his firm became comfortable it would also not incur massive cost overruns being experienced by other oilsands operators. The project's attractiveness was further enhanced by the oilsands proximity to the American market, Hunt said.

Earlier in 2003 (September) Devon Energy announced it was moving ahead with its $500mn Jackfish heavy oil project in Northern Alberta. The company expects to produce 35,000 b/d of oil from the project, which will also use steam assisted gravity drainage technology.

UK oil and gas production update

The Royal Bank of Scotland's latest (December) *Oil and Gas Index* shows that UK combined oil and gas production for September 2003 increased on August, to reach 3,667,507 boe/d, although it was down by 2.1% on the year.

September's oil production fell on both the month and the year to an average of 1,858,409 b/d. Gas production increased on the year by 5.7% to 9,716mn cf/d, although this was a slight drop on the month.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Sep	2,127,594	9,195	28.40
Oct	2,301,341	11,165	27.60
Nov	2,001,329	11,803	24.20
Dec	2,353,028	12,582	28.30
Jan 2003	2,274,870	12,890	31.20
Feb	2,215,831	13,599	32.20
Mar	2,251,714	12,420	29.90
Apr	2,092,765	10,868	27.50
May	1,948,620	9,659	25.60
Jun	1,940,265	9,221	27.30
Jul	1,957,888	9,250	28.50
Aug	1,907,113	9,842	29.50
Sep	1,858409	9,716	26.80

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Buzzard given green light to take-off

The UK Department of Trade and Industry has granted EnCana (UK) and its co-venturers approval to develop the Buzzard oil field – the largest field to be discovered in the North Sea in the past decade. First oil is planned for late 2006.

Buzzard's total recoverable reserves are estimated at more than 400mn barrels of oil and gross production is expected to reach a plateau of 180,000–190,000 b/d in 2007. The £1.35bn ($2bn) Buzzard development will consist of three bridge-linked steel platforms supporting facilities for drilling, production, and utilities and accommodation respectively. The facilities include two subsea water injection manifolds located about two kilometres from the platform. The crude oil will be transported to the mainland via a pipeline tie-in to the nearby Forties pipeline system. Gas will flow to market via the Frigg pipeline system.

When completed, Buzzard is expected to be a hub for a number of existing and potential discoveries in the area.

Field partners are EnCana (operator, 43%), Intrepid Energy North Sea (30%), BG Group (22%) and Edinburgh Oil & Gas (5%).

Growth in deepwater oil production

Deepwater oil production, which averaged some 2.4mn b/d in 2002, is expected to grow to exceed 8mn b/d over the next 15 years, according to John Westwood of energy analysts Douglas-Westwood, addressing delegates at the Deep Offshore Technology Conference in Marseilles, France. He also said that he expected deepwater to be the most significant source of domestic production for the US.

Quoting from his company's energy business studies published in *The World* series, Westwood stated that over 100mn barrels of deepwater oil has been produced to date. Brazil is currently the world leader, but its deepwater production is likely to be greatly exceeded over the next decade by that from West Africa and the US Gulf of Mexico. In 2002 Brazil and the US produced about 1mn b/d. Brazil is expected to increase output to some 1.5mn b/d, while the US is forecast to grow to some 2.8mn and West Africa, which currently produces about 500,000 b/d, is expected to reach about 3.9mn b/d.

One significant issue in increasing West African deepwater production will be Nigeria's ability to persuade Opec to increase its quota and Westwood believes Nigeria is negotiating hard to achieve this objective.

Douglas-Westwood forecasts that worldwide deepwater activity will require capital expenditure exceeding $56bn over the next five years. This will continue to be focused in the 'golden triangle' of Brazil, the US and West Africa. The five-year industry shopping-list for installations in water depths beyond 500 metres is likely to include: 826 subsea wells, 242 surface wells, 195 templates and manifolds, 3,408 km of control lines, 8,137 km of pipelines and 64 platforms (mainly floaters).

Deepwater drilling has also been enjoying good growth as shallow-water activity has declined over the past few years. This growth is set to continue, with combined spend on exploration, development and appraisal drilling set to total $40bn over the current five-year period.

Floating production systems will continue to be the preferred method for major deepwater field developments. Considering the period 2004–2008, information on Douglas Westwood's 'World Floating Production Database' shows that 61 floating production systems of various types are being considered for installation and 32 of these are FPSOs. Douglas-Westwood forecasts that five-year expenditure on deepwater floaters will grow from a present average of some $3.5bn/y to $6.5bn by 2008.

'The really exciting opportunities lie in the identification and exploitation of "Gamechanger" technologies,' said Westwood. 'New floating production concepts, new pipe lay methods such as the Naturalay floating drum system, subsea processing, seabed drilling, autonomous underwater vehicles, etc. Subsea processing offers a particular opportunity,' he said. In its 'most likely scenario', *The Subsea Processing Gamechanger Report* (a major study that was recently completed with OTM Consulting) values the subsea processing market at $370mn over the period 2003–2007 and expects this to grow to $1.6bn over the period 2008–2012.

Vigdis extension

The estimate of recoverable reserves in Statoil's subsea Vigdis extension development in the Norwegian North Sea has been upgraded by 8mn barrels to 12mn barrels of oil. At today's oil prices, this increase enhances the value of the North Sea project by up to NKr2.5bn.

The two first Vigdis extension wells came onstream in October, more than two months ahead of schedule. Furthermore, at just under NKr2.6bn, the cost of this development is roughly NKr400mn below its original budget, states the company.

Preliminary estimates show that, with the upgrading in reserves, the development should provide some 60mn barrels of additional oil from the Vigdis satellite.

Auzzie/E. Timor talks

The Australian and East Timorese Governments are reported to have begun preliminary talks on the future of a sea bed boundary between the two countries. They are seeking an agreement on the area's rich oil and gas reserves. East Timor wants the boundary to run along a line equidistant to the two countries, rather than the current border that is in Australia's claimed economic zone.

If successful, East Timor would gain administrative control over the Bayu-Undan gas project and the planned Greater Sunrise gas development. It could also give control of the Laminaria-Corallina oil field to either East Timor or Indonesia, forcing the Australian Government to surrender more than $286mn/y in taxes and royalties.

In Brief

the offshore Dorra gas field to international arbitration if bilateral talks fail.

***Brazil's state oil company Petrobras** has outlined plans to return to the Middle East after a 20-year absence, as part of its wider international expansion programme. Early next year the company will bid in an auction of natural gas exploration licences in Saudi Arabia. Meanwhile, negotiations continue in Iran, where Petrobras wants to drill for oil on at least one block.*

***Total (30%) reports that it has signed** an agreement under which a consortium comprising it, Saudi Aramco (30%) and Shell (40%) will explore for gas in a 200,000 sq km area in the southern part of the Rub Al-Khali (Empty Quarter) in Saudi Arabia. Tenders for seismic surveying are expected to be issued in 1Q2004.*

***Total and Statoil are reported to be in** negotiations to develop Iran's 26bn barrel oil-in-place Azadegan oil field.*

***Global Petroleum is understood to** have formed a joint venture with Fira International, a consortium of private international investors, which will apply for a production sharing agreement to undertake oil exploration and development in the Chamchamal area in northern Iraq. Fira has committed to fund an initial capital programme of $30–$40mn over the first two to three years of a production sharing agreement.*

***The Iraqi Oil Minister Ibrahim Bahr** al-Ulum is reported to have stated that Iraq may revise its West Qurna-2 contract with Lukoil. The contract, originally signed in 1977, was annulled in 2002 amidst assertions that the Russian oil company was not fulfilling its terms, which Lukoil strongly denied.*

Russia & Central Asia

***Having drilled 90,000 metres in 2002,** Turkmenistan is planning to triple exploration drilling by 2005, according to the Oil & Gas Ministry.*

***Ukraine's Ecology and Natural** Resources Ministry is reported to have issued a tender for the exploration and development of the Priazovskoye gas field in the Zaporozhye Region. Field reserves are put at 2bn cm of gas.*

Upstream news is cont'd on p41

In Brief

UK

***A new Bill to promote 'cleaner, greener power' and competitive and reliable energy supplies has been introduced in the House of Lords. The Energy Bill can be found at* www.publications.parliament.uk/pa/pabills.htm *The Energy White Paper is available on the DTI website at* www.dti.gov.uk/energy/whitepaper.index.shtml**

Europe

***The latest projections from the European Environment Agency (EEA) for the EU's total greenhouse gas emissions can be found at* www.reports.eea.eu.int/environmental_issue_report_2003_36.sum**

ExxonMobil and Qatar Petroleum (QP) have acquired a 90% interest in the Edison Gas North Adriatic LNG terminal project. Also, Ras Laffan Liquefied Natural Gas Company Limited II (RasGas II) and Edison Gas of Italy have signed amended sale and purchase agreements to increase LNG supplies from the initially agreed level of 3.5mn t/y of LNG to 4.7mn t/y, commencing in 2007.

North America

Petro-Canada has approved a capital and exploration expenditure programme totalling $2,595mn for 2004.

ConocoPhillips has reportedly stated that it expects to increase asset sales by $1bn to $4.5bn and raise its merger-related cost-cutting target by $500mn to $1.75bn in 2004. It is also planning to hold capital spending at $6bn.

Enron's Houston-based headquarters is to be sold at auction, two years after the group went bankrupt. The building has been valued at $92.5mn.

An ExxonMobil affiliate, Golden Pass LNG, has announced plans to develop a $600mn LNG receiving terminal near Sabine Pass, Texas. The proposed terminal is expected to be operational by 2008/2009, with an initial processing capacity of 1bn cf/d of LNG.

Respol YPF is to sell Shell Western LNG some 2bn cm of LNG from Trinidad & Tobago through December 2005, to be delivered to the Cove Point LNG regasification terminal in the US.

NEWS Industry

Port Pelican LNG terminal approved

ChevronTexaco subsidiary Port Pelican has received approval for a deepwater port licence from the US Maritime Administration of the Department of Transportation to construct, own and operate an LNG receiving and regasification terminal, to be located approximately 40 miles off the Louisiana coastline in the Gulf of Mexico.

The Port Pelican development will consist of an LNG ship receiving terminal, LNG storage and regasification facilities, and pipeline interconnection to existing offshore infrastructure to deliver natural gas into the US interstate gas pipeline network via the Henry Hub.

The proposed offshore LNG terminal will be constructed using a freestanding concrete gravity based structure (GBS), along with mechanical regasification facilities capable of handling 1.6bn cf/d of gas. The company anticipates beginning construction of the GBS in 2004. Commissioning is projected for 2007, followed by start-up operations.

World economic growth and energy demand

Each year, ExxonMobil prepares a detailed, long-term outlook of worldwide economic growth and energy demand. These forecasts are a significant component of the company's business planning, helping to guide investment. *The Energy Outlook* analysis has a 2020 horizon, but where key future trends are outside of this window, the analysis has been extended to 2050. The pertinent economic and energy trends included in the outlook are benchmarked with those of the International Energy Agency (IAE), the US Department of Energy and other leading economic and energy forecasters.

The key points from this year's analysis are:

- Worldwide energy-demand growth is a key enabler of, and closely linked to, economic growth. By 2020 the world will need close to 40% more energy, primarily due to increased energy use in less-developed countries.
- Oil and gas will continue to be the primary sources of energy, at least through the mid-century.
- Higher motor fuels consumption from vehicle penetration and growing GDP will increase demand, offsetting sizable efficiency improvements.
- Gas will continue to grow faster than the other energy forms, especially in power generation.
- Renewables will grow quickly, supported by government subsidies, but will contribute only a small fraction of energy supply.
- Energy supplies need to be developed both to meet new demand and to replace maturing resources. This requires access to discovered resources, economic development of unconventional resources, continued technology advances and adequate financing.
- Finally, groundbreaking research is required to develop a portfolio of energy options. The ExxonMobil-supported Global Climate and Energy Project at Stanford University is one example of the company's commitment to developing new commercially viable technologies to produce reliable and affordable energy while reducing greenhouse gas emissions.

For more information, visit **www2.exxonmobil.com/corporate/Notebook/Supply/Corp_N_SupplyOutlook.asp**

Sustainable development in Nigeria

USAID (the United States Agency for International Development and Shell are to become partners in a $20mn sustainable development project in Nigeria. The partnership is the largest so far under USAID's new business model, the Global Development Alliance, which promotes public-private alliances to implement sustainable development programmes around the world. By partnering with the private sector, developing country governments and non-governmental organisations, USAID is able to extend its reach and effectiveness in responding to new global challenges.

Shell will contribute some $15mn over the next five years to the partnership and USAID will contribute $5mn. The partnership's programmes will aim to help build capacity and opportunity for Nigerians in the strategic areas of agriculture, health, and small and medium size enterprise. USAID and Shell plan to focus their work on food security through a cassava cultivation support programme, the prevention of malaria, and supporting the export shrimp industry.

NEWS Industry

Latest *Prestige* findings back ABS

The first piece of steel recovered from the wreck of the *Prestige* appears to soundly refute allegations made by the Spanish Government that the vessel was in poor structural condition, reports classification society ABS. The steel was recovered by a Spanish expedition that used remotely controlled underwater vehicles (ROVs) to cut and retrieve a section of hull plating from the starboard side of the vessel. As reported in the Spanish press, ABS states that it has learned that thickness measurements taken on board the recovery craft confirmed that the material met class rule requirements. The plate, now in the custody of the court in Corcubion, had a minimum thickness at least equivalent to the design scantling of 20.5mm.

As reported, the sample also appeared to confirm that the interior coating of the plate was in good condition and that the plate had been subject to only mild exterior pitting from corrosion. ABS says it has also learned that extensive close-up video footage of the vessel has been taken by the ROVs and also appears to confirm that the plating thickness and condition were adequate.

'This evidence strongly refutes the continuing public allegations that have been made regarding the condition of the *Prestige* at the time of the casualty,' said ABS spokesman and Vice President Stewart Wade.

The most recent allegations stem from Spanish press reports of a fax, purported to have been sent to ABS by the temporary relief master of the *Prestige* in August of 2002. This fax – only just made public, a full year after the incident – is reported to enumerate various mechanical and structural defects.

BG and Petroplus plan LNG imports to UK

BG Energy Holdings, a subsidiary of BG Group, has signed a Memorandum of Understanding (MoU) with Petroplus International for the joint development, ownership and operation of an LNG import and regasification facility at Milford Haven, Wales. BG intends to acquire a 50% equity stake in Dragon LNG, a special purpose project company established to develop the project. In addition to this equity position, BG intends initially to contract for the use of 2.2mn t/y of capacity at the facility. This represents half of the initial planned throughput capacity.

The new facility, which is expected to be operational in 2007, has received planning permission and would deliver natural gas into the UK market via the national transmission system. With the UK set to become a net importer of gas in the latter half of this decade, it would provide increased security of supply through access to a range of international gas supply sources.

BG outlines LNG development plans

BG Group recently held a presentation in London for investors and analysts on the Group's LNG business. Key points from the presentation include:

- BG expects to be the largest participant in the Atlantic Basin, in terms of the aggregate of volumes of LNG contracted for import and export, by 2007.
- The company is considering sourcing LNG from the Damietta LNG project in Egypt.
- At the end of October 2003, construction of Egyptian LNG Train 1 was 45% complete against a schedule of 30% and Train 2 was 25% complete.
- BG expects to deliver more than 100 cargoes of LNG to the US by the close of 2003.
- Lake Charles' average LNG send out in the year to November 2003 was 765mn cf/d, representing 1% of daily US gas demand.
- By the end of September 2003, BG had been responsible for 62% of all imports of LNG into the US this year.
- Following a release of capacity by Duke Energy agreed recently, BG will have access to 100% of the capacity at Lake Charles from 1 January 2004.
- By 2007, around 20% of BG's equity gas production will be monetised via its LNG schemes, an increase of almost two and a half times over today's position.
- At Henry Hub prices of between $2.50 and $3.50, BG expects long-term LNG purchase contracts typically to deliver ex-ship prices of 80–85% of Henry Hub.
- As an illustration, BG estimates that, at mid-cycle prices, purchased LNG generates a net present value equivalent to 45% of that created by equity gas monetised through LNG.
- BG estimates that the future differential between the prices achieved currently at Lake Charles and Henry Hub will reduce from the current level of around 15 cents/mn Btu to nearer 10 cents/mn Btu.

In Brief

***Global emissions of the greenhouse gas** carbon dioxide (CO_2) are forecast to rise by 3.5bn tonnes, or 50%, by 2020, Randy Broiles, Global Planning Manager for ExxonMobil's oil and gas production unit, is reported to have stated.*

Middle East

***Oman LNG is understood to have signed** a six-year sales and purchase agreement with BP to supply 3.6mn tonnes of LNG from 2004. This allows BP to receive up to 12 cargoes of LNG per annum to be shipped to Spain. Oman is in the process of building a third LNG train to boost output by 50%.*

Russia & Central Asia

***Gazprom has announced that it has** selected LNG as the preferred export route for Shtokmann gas. Field reserves are put at more than 3tn cm.*

***Gazprom is reported to have singled** out for development an area in the Obskaya bay in the Arctic Kara Sea, with proven resources in excess of 800bn cm of gas. The company is due to start work on Obskaya from 2009–2010 and plans to produce 82bn cm/y by 2021.*

***The forecast $15bn of revenue from** oil and gas sales in Russia will contribute to some 20% of 2004 budget revenues. Oil production is expected to reach 520mn tonnes and gas output 740bn cm in 2020.*

***Kazakhstan's state oil transport company** KazTransOil (KTO) is reported to have outline proposals to double the capacity of the Atyrau-Samara pipeline to 30mn tonnes.*

Africa

***The Nigerian Government is expected to** sell eight oil and gas corporations as part of its privatisation programme during 2004. Included are the Warri, Port Harcourt and Sierra-Leone refineries; the Pipeline and Products Marketing Company; and Nigerian Gas Company.*

***Nigeria LNG (NLNG) has reportedly** signed a sale and purchase agreement (SPA) with Shell, under which the oil company will lift 1.4mn t/y of Nigerian gas for supply to the Iberian Peninsula, North America and Mexico. The contract, to be supplied by the proposed sixth train of the Bonny LNG plant, is for a period of 20 years.*

In Brief

UK

BG Group is reportedly planning to *sell its 51% stake in Northern Ireland gas distributor Phoenix Natural Gas to water and gas utility East Surrey Holdings in a deal worth £120mn. East Surrey also plans to buy the 24.5% of Phoenix owned by US-based distributor Keyspan.*

Europe

Norsk Hydro Energy has signed an *agreement with Duke Energy International for purchase of the gas sales and marketing organisation of Duke in the Netherlands – Duke Energy Europe Northwest – for an undisclosed sum.*

Nord Pool and DONG Transmission have *created a study group – GasPool2004 – to investigate the possibilities of establishing a Danish gas trading hub. The study group is expected to present its results and recommendations in April 2004. On 1 January 2004 the Danish gas market will be fully liberalised and all gas consumers will be able to choose their gas supplier.*

Polish company PKN Orlen has *acquired 494 German filling stations from BP-Germany, gaining a 7% market share in northern Germany, reports* Stella Zenkovich.

Total has inaugurated its first wind *power plant at the Les Flandres refinery in Mardyck, France. The wind turbines have a total installed capacity of 12 MWly, equivalent to the household electricity consumption of 15,000 individuals. The three models selected in this 15mn pilot project combine high electrical output, a small footprint and low noise levels. Output is sold to Electricité de France*

Eastern Europe

Oiltanking Hungary has became the *100% owner and operator of a terminal facility in Budapest. The 17,000 cm capacity terminal is being used for the storage and throughput of mineral oil products. The acquisition makes Oiltanking the first independent storage provider present on the Danube in Hungary.*

Bulgaria's Prista Oil of Rousse has *gained a stable position in Romania,*

NEWS Downstream

Total and GdF plan for gas liberalisation

Total and Gaz de France have signed a 'protocol of intent' to separate their cross-shareholdings in Gaz du Sud-Ouest (GSO) and Compagnie Francaise du Methane (CFM), their jointly-owned gas transmission and supply subsidiaries in France. Under the protocol, Total would become the sole shareholder in GSO, while Gaz de France would become the sole shareholder of CFM.

The protocol reflects Total and Gaz de France's shared commitment to adapting to the structural changes in the French gas market. From 1 July 2004 the industrial and non-residential markets will be open to competition. As of this date currently integrated gas utilities will unbundle their transmission and trading operations. From 1 July 2007 the market will be fully open for residential customers.

In addition, the protocol will permit Total to acquire a one-third interest in the Fos Cavaou regasification terminal project in southern France. The LNG facility is due to be commissioned in 2007 and will have an initial capacity of 8.25bn cm, which could be subsequently expanded.

News from the European Union

The European Union (EU) Council of Ministers has approved a system of minimum EU tax rates for natural gas, which until now have only applied to mineral oils, writes *Keith Nuthall*. From the New Year, gas used for heating must attract indirect taxes (excluding VAT) of at least 0.15 per GJ for business use and 0.30 for non-business use. Ministers and the European Commission want to promote cross-border gas sales by making gas taxes more similar. Rates for mineral oils were updated for the first time 1992, although many national exemptions still apply. In other EU energy news:

- The EU and Russia have discussed denominating Russia's oil and gas exports in euros, rather than US dollars. The idea was supported at a EU-Russia Energy Dialogue conference involving Russia's Deputy Prime Minister and the lead official at the European Commission's DG Energy and Transport.
- EU legislation banning single-hull tankers from carrying heavy grades of oil to or from EU ports is now in force. It also bans all tankers more than 23 years old from EU ports immediately. The International Maritime Organisation has opposed the move, saying such decisions should be taken globally.
- The European Parliament has approved writing the EU's Kyoto Protocol commitments into European law, obliging Member States to monitor and report emissions of greenhouse gases and install programmes to reduce them.
- A special tax refund scheme for shuttle tankers working off Norway has been approved by the European Free Trade Area (EFTA) Surveillance Authority as an allowable use of state aid under European law.
- The European Bank for Reconstruction and Development (EBRD) has urged post-communist countries to hasten the liberalisation of their energy sectors. This would help integrate them with the EU economy. They also faced challenges in building up 90 days of oil stocks, as required by European law, noted the bank.

Addressing Scottish anomaly under BETTA rules

The UK Department of Trade and Industry has issued a consultation document recommending proposals and seeking views on how to treat smaller generators (below 100 MW) directly connected to the 132 kV transmission system in Scotland post BETTA.

The consultation document – *Small Generator Issues under BETTA* – issued jointly with industry watchdog Ofgem seeks, in particular, to address an anomaly that will arise under BETTA. If there are two identical sub-100 MW generators, one in Scotland and one in England or Wales, both connected at 132 kV, the one in England would pay distribution charges while the one in Scotland would pay transmission connection and use of system charges.

The consultation outlines DTI/Ofgem's intention to address this anomaly by giving smaller generators directly connected to the 132 kV network in Scotland an exemption from paying the residual (non-locational) part of the transmission use of system charge.

The consultation document seeks responses no later than 15 January 2004. The document is available at **www.dti.gov.uk/energy/domestic_markets/electricity_trading/index.shtml**

NEWS Downstream

First Japanese trial of Shell GTL Transport Fuel

Showa Shell Sekiyu, Mitsubishi and Shutoken Co-Op Consumers' Cooperative Union have launched Japan's first public trial of Shell's gas-to-liquids (GTL) Transport Fuel. The seven-month trial follows the October 2003 announcement that Qatar Shell GTL plans to invest $5bn in what is reported to be the world's first world-scale GTL plant in Qatar.

The GTL Transport Fuel can be used in conventional diesel engines and can be blended into conventional diesel fuel, states Shell. Free of sulphur, the fuel has a very high cectane number (a measure of combustion performance in diesel engines) and is claimed to offer significantly lower vehicle emissions of pollutants such as nitrogen oxides, particulates, carbon monoxide and hydrocarbons than conventional diesel fuel.

Two to three of Co-Op's delivery trucks will be filled up with a blend of GTL Transport Fuel and conventional diesel fuel and will carry out their deliveries in the Tokyo, Kanagawa and Saitama areas. Over the summer months a fleet of VW Golfs and a DaimlerChrysler bus have been successfully trialled with 100% GTL Transport Fuel in Berlin and London, reports Shell.

Indian technical due diligence study

Foster Wheeler Energy has completed a technical due diligence study for the Hindustan Petroleum Corporation Limited (HPCL), the second largest refining and marketing oil company in India. The contract represents the first due diligence study executed by Foster Wheeler for a major Indian oil company.

The technical due diligence report concerned two refineries – the Mumbai and Visakhapatnam refineries – and two cross-country pipelines. The Indian Government is currently involved in a major disinvestment programme, and is seeking to sell its 34.01% share of HPCL. It is estimated that this share is worth in excess of $2bn.

The Mumbai refinery has a capacity of 5.5mn t/y and the Visakhapatnam refinery has a capacity of 7.5mn t/y. Both produce a range of high-quality refinery products, including lubricating oils. The two cross-country pipelines are the Mumbai-Pune pipeline, a 161-km multi-product pipeline that delivers refined white oil products to terminals within Maharashtra state, and the Visakh Vijayawada-Secunderabad pipeline, a 572-km multi-product pipeline delivering refined white oil products to terminals within the Andhra Pradesh state.

Need to focus on delivering high quality service

As fleet managers switch on to online reporting, new research from independent market analyst Datamonitor finds that fuel card providers must focus on delivering a high quality service or stand to lose significant market share by the end of 2004. The online offering is becoming more and more important to customer satisfaction – some 41% of fleet managers would not switch for a better price without it and, of those who would, 38% would forego online services only for savings of 6% or more. Yet at the same time, providers should also be aware that the majority of customers never use 20% of reporting.

Simplicity is the key, and heavy monetary investment is not necessarily the answer. Datamonitor's research reveals that almost all customers prefer more accurate data rather than additional services they are unable to use.

Protecting Scottish energy subsidy

Scottish energy consumers should not lose out as a result of European legislation UK Energy Minister Stephen Timms said recently. The cost of supplying electricity to the Highlands and Islands of Scotland means that the costs of energy distribution in northern Scotland is high compared to that of the rest of the UK. Consumers in the north of Scotland are currently protected by a distribution subsidy, provided by Scottish and Southern Energy (SSE), known as 'hydro benefit'.

The energy regulator Ofgem has been advised that the hydro benefit subsidy may not be compliant with EU legislation and has announced that it intends to remove hydro benefit, subject to consultation. The removal of this subsidy could have a significant repercussion on consumer bills in the north of Scotland.

Stephen Timms said he recognised the potential problems and promised to investigate all avenues to protect consumers.

In Brief

aided by its partnership with Texaco, and reports that its fuel sales have risen by 36.5% in Macedonia, 35% in Serbia and 18% in Hungary, writes Stella Zenkovich. *Meanwhile, Petrol has opened its 100th filling station in Levski, Bulgaria, and is planning to open 40 more outlets, with C-stores, by the end of 2004. OMV is to launch an 8mn hi-tec service station network in Bulgaria in March 2004 and is seeking a partner to manage the project.*

***Gas tariff increases have recently been** announced by the Bulgarian state energy regulatory commission, reports* Stella Zenkovich. *Tariffs have risen by 10% for consumers linked to distributors' networks, and by 9% for those linked to the Bulgargaz distribution net.*

North America

***Marathon is to invest nearly $300mn** increasing the crude oil processing capacity at its Detroit refinery by 35% to 100,000 b/d. Other elements of the expansion programme will enable the refinery to produce new clean fuels and further control air emissions. The company expects to complete the project in 2005.*

***Shell Oil is to discontinue operations** at the US Bakersfield refinery by 1 October 2004 as part of an ongoing programme to upgrade the business portfolio of the Shell Group in order to improve returns in the underlying business.*

Middle East

***Foster Wheeler Energy has been** appointed as a technical consultant to a major petrochemical complex planned by Saudi Arabia's Project Management & Development Company. The complex, which will have a total investment value of $3.5bn, will consist of an ethane/butane cracker producing ethylene, propylene and benzene feedstocks for downstream petrochemical units within the PMD cracker complex.*

Russia & Central Asia

***TNK-BP is to invest $30mn** modernising the Lisichansky refinery in Ukraine in 2004. The company is also planning to expand its presence in the Ukrainian fuel retail market by*

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investing $53mn on the construction and acquisition of a network of service stations over the year. Together with its partners, TNK-BP intends to build about 100 service stations in different regions of the Ukraine, acquiring a further 270 sites by buying shares in existing networks. At the same time the company plans to increase its oil storage depot network to 12 by the end of 2004.

Asia-Pacific

***A new report that sheds considerable** light on the extent to which a more liquid wholesale gas market might arise in Australia in the medium-term, and what form it might take, has been released by the Australian Gas Association (AGA). Drafted by the Australian Bureau of Agricultural and Resource Economics (ABARE0, the* Australian Gas Markets: Moving Towards Maturity *report can be downloaded from the AGA website at* **www.gas.asn.au** *(go to* What's New*).*

***Powerco of Australia has signed** distribution and retail contracts with the Tasman Group, owner of the Longford meatworks in Tasmania, for the supply of natural gas to its site. The Tasmanian Government has agreed to provide conditional funding to facilitate the extension of the gas network to Longford, Tasmania.*

Latin America

***Gas Natural of Spain is reported to** be planning to buy bankrupt Enron's 25.39% stake in Compania Distribuidora de Gas de Rio de Janeiro and its 33.75% holding in CEG Rio. The company already has shares in both Brazilian gas distributors, the deal boosting its stakes to 54.16% and 72%, respectively. Gas Natural also owns Enron assets in Puerto Rico.*

Africa

***A total of 34 investors have expressed** interest in taking a 51% stake in Nigeria's four existing state-owned refineries with 445,000 b/d combined capacity, reports* Stella Zenkovich.

***Woodside Petroleum (operator, 45%),** Repsol YPF (35%) and Hellenic Petroleum (30%) have finalised a 30-year exploration and production sharing contract with the Libyan National Oil Corporation. The deal covers five exploration blocks in the onshore Sirte Basin in northern Libya and one in the onshore Murzuq Basin in western Libya. The minimum exploration work commitment will involve geological studies, seismic acquisition and 13 exploration wells over the initial six-year period. The commitment also covers a three-year feasibility study for the development of a remote field in the Murzuq Basin. The study includes an option to negotiate an appraisal and development agreement for the field within a further three years.*

***Foster Wheeler has been awarded a** $45mn engineering, procurement and construction management (EPCm) contract by Sasol for a new waste recycling facility at Sasol's Secunda operations in South Africa. This waste recycling facility, with a total investment value of 500mn rand ($75 million), is reported to be the first of its kind in Africa. It will treat the waste from what is the largest coal-to-liquids plant in the world.*

***Shell has opened its first com-**pressed natural gas (CNG) station in Egypt, at Giza, reports* Stella Zenkovich. *By 2006 the company plans to have built a further 35 CNG outlets, converting 11 more service stations to the fuel.*

Funding approved for BTC pipeline

The European Bank for Reconstruction and Development (EBRD) has approved up to $250mn in loans to the Baku-Tbilisi-Ceyhan (BTC) pipeline. This followed a decision by the International Finance Corporation (IFC) to approve a similar financial package on 4 November 2003. Agreement on the two loans comes after over two years of extensive monitoring and scrutiny of the project's environmental and social impact, as well as a thorough public consultation process. The loans, which attract commercial rates of interest, are conditional on the project continuing to meet its stringent public commitments – which will be subject to formal quarterly audits by the lenders.

The Baku-Tbilisi-Ceyhan pipeline will cost $2.95bn to construct ($3.6bn total project cost), with the balance of the finance being provided by equity investment, export credit agencies and commercial banks. Financial close is due by the end of the year. 'The involvement of both the IFC and EBRD will help ensure that this investment results in real benefits for those most directly affected – from the 450 villages along the pipeline route, to the citizens of Azerbaijan, Georgia and Turkey,' said BTC Chief Executive Michael Townshend.

The 1,760-km pipeline will allow 1mn b/d of oil to be exported from the Caspian without increasing tanker traffic through the Turkish Straits. First oil from the pipeline, which is already around 40% complete, will be exported from the Mediterranean port of Ceyhan in 2005.

Partners in BTC Company are: BP (operator), Socar, Unocal, Statoil, TPAO, Eni, Total, Itochu, Inpex, ConocoPhillips and Amerada Hess.

The BP-operated South Caucasus Pipeline (SCP) will be built alongside the BTC line and will take gas from the BP-operated Shakh Deniz field to the Georgia-Turkey border. First gas exports are expected in 2006.

The EBRD has also approved financing of up to $30mn for the $3.2bn Azeri-Chirag-Gunashli Phase One oil field, with the equivalent sum syndicated to commercial banks. A similar package was approved by the IFC on 4 November.

Cutting energy bills and climate change

Consumers could benefit from lower bills and help to combat climate change by being able to sign up to longer contracts with energy companies through a new pilot project announced by the UK Government on 24 November. It is claimed that up to one million households could benefit under the scheme.

Under existing rules, consumers can switch energy suppliers after just 28 days. New rules will allow them to choose a longer contract and, in return, receive energy efficient products and services from their supplier – such as house insulation, energy efficient boilers and domestic appliances, or low-energy light bulbs.

The pilot scheme has been developed by the Energy Services Working Group (ESWG), set up following Energy White Paper proposals, with representatives from government, the regulator Ofgem, consumer body Energywatch and industry.

Prize-winning projects

A host of key industry executives gathered at London's Savoy Hotel for the annual IP Awards Dinner on 20 November 2003. Now in its fourth year, 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 accomplishments in the international arena. The IP Awards 2003 were organised in association with Wood Mackenzie.*

Main picture: The stage is set for the 2003 IP Awards at the Savoy Hotel, London

Above: Sir Chris Bonington, CBE, mountaineer, was this year's guest speaker

All IP Awards photos: Jim Four

The Energy Institute received 125 entries for the seven award categories – Communication & People, Community Initiative, Environment, Innovation, International Platinum, Safety and Technology – an increase of more than 50% over last year. Judging for each category is based on the achievements deemed to have had the most impact or potential impact on the industry.

Sir Chris Bonington CBE, mountaineer, writer and photographer, took the rostrum to officially open the Awards Ceremony. He said that everyone has 'their Everest' to climb, whether it was a literal Everest or the challenges found in business. The IP Awards represented supreme achievements by those who had won them. However, it was important not to be afraid of failure because it was only by taking up and meeting the challenge that people could attain their dream. He then went on to describe how he had led a Norwegian team up the south-west face of Everest in 1972 – a first that meant they all collectively and individually attained their dream.

communication and people award

Sponsored by **Norman Broadbent**

Winner: **Schoolscience – *'Discover Petroleum'***

Left to right: Nigel Burt, Gill Haben, Charles Tracy, sponsor Ian Manson and Barry Johnson

The *Discover Petroleum* website – **www.energyinst.org.uk/discover** – was commissioned by the former Institute of Petroleum as part of its education and careers strategy to support the industry as a whole. It has been designed and developed by Industry Supports Education, consultants to the Institute, working with Gill Haben, Education and Training Manager of (the then) IP, now the Energy Institute.

Discover Petroleum has been developed as a free, interactive educational experience using games, illustrations, quizzes and virtual reality. It is being built to appeal to different ages and levels of knowledge, and to a wide range of users, from primary and secondary school children, to graduates, educators and the general public – in fact, anyone seeking knowledge about the industry and its processes.

The content is factual, fun and, crucially, presented from an *independent* viewpoint. As well as covering science in the industry, other topics aligned to national curricula are included, such as geography and maths. Critically, industry career opportunities are illustrated too.

The initial phase developed the Key Stage 2 section for older primary children, who are introduced to the five stages of creation from fossil remains, its discovery, retrieval, refining and how it is put to use. This is done through a set of games along the 'hydrocarbon trail', each setting a small challenge related to part of their curriculum in the context of the world of petroleum.

The site has been further enhanced by a virtual visit to Fawley oil refinery, which has been sponsored by ExxonMobil. Most recently, a virtual visit to the Captain platform in the North Sea has been developed, and sponsored by ChevronTexaco (see *Petroleum Review*, December 2003).

community initiative award

Sponsored by **Accenture**

Winner: **BP Exploration Angola – 'Emergency Humanitarian Aid for Angola: A BP Team Effort'**

Left: Sponsor Colin Sloman Partner, Accenture, presents winner Rich Smith, Vice President, External Affairs, BP Angola Business Unit

In 2002 Angola emerged from years of war and suffering. There was no infrastructure, destruction and desolation were immeasurable, and there was a threat of an imminent humanitarian disaster. BP Angola decided to do something to help and launched an appeal throughout the company. The United Nations and Angolan-based NGO's (non-government organisations) proposed a number of humanitarian assistance projects, from which two were selected:

- CARE Angola's project helps communities restart farming activities in Bié, a war-torn province in south-central Angola. As well as providing seeds and tools to the farmers, training sessions on farming practices and small cooperatives have been set up to market surplus products. Some 15,000 farmers and their families have benefited from this project.
- The Christian Children's Fund (CCF) project provides emergency health and nutrition to internally displaced people in Bocoio to the south of the country. CCF has set up community kitchens, provided health assessments for mothers and babies, and given out vaccinations. Volunteers have been trained in community healthcare and hygiene practices. Direct beneficiaries are estimated at 67,000 people.

BP Angola raised almost $1mn through this appeal from three sources – money raised by employees through activities such as sponsored marathons, cake sales etc (which was doubled through the company's 'matching' programme); money donated by the BP Angola Business Unit; and money donated directly by the BP Foundation.

Positive features of the programme are the involvement of local NGO's, the active participation of employees throughout the company, the long-term sustainability of the projects and the commitment to reach and impact large numbers of disad-

environment award

Left to right: Mike Mannering, Quality Health, Safety and Environment Director, Schlumberger; Mark Thurber, General Manager, WALSH-Ecuador; Paul MacInnes, General Manager OXY Ecuador and Jimmy Vela, HES Manager, OXY Ecuador

Sponsored by **Schlumberger**

Winner: **Walsh Environmental Scientists & Engineers – 'Canopy Bridges along a Rainforest Pipeline in Ecuador'**

The Eden-Yuturi field, developed by Occidental Petroleum in block 15, is located in an ecologically sensitive region of the Ecuadorian Amazon. The environmental consulting firm Walsh and Occidental Petroleum identified the new 135-km long pipeline corridor that connects this new production to the newly built OCP pipeline as the most significant social-environmental and construction challenge of the project.

Protection of biodiversity was a key management goal in the 42-km long corridor. A strategic decision was made to bury the pipeline and to construct no permanent access roads – consistent with Occidental's philosophy and commitment to minimising environmental impact.

One of the greatest concerns was the barrier effect of breaking the forest canopy by cutting a 15-metre wide corridor. This barrier would effectively cut off migration routes of arboreal mammals, which rarely walk on the ground. An innovative solution was devised – the use of 'canopy bridges' to provide pathways of migration for arboreal mammals (see p26). A 'canopy bridge' is simply a short section where the working corridor has been narrowed to seven metres to preserve the canopy connection.

During the clearing of the working corridor, only smaller trees and brush were removed in the canopy bridges. Then a sandwich of synthetic fabrics, riprap and soil was installed to protect the thin topsoil and roots from damage while moving heavy equipment through the canopy bridges.

After construction, five out of the 15 metres of the pipeline corridor were reforested with the co-operation of the native communities that own the land. Movement of arboreal mammals, mainly monkeys, has been observed at all of the canopy bridges, during and after construction. This experimental technique has proved to be effective in conserving biodiversity in tropical rainforest and can be used in other linear projects in tropical environments.

innovation award

Left to right: Andy Swiger, ExxonMobil; Paul Garnham, Recruitment Co-ordinator EPE-H-D; Shell EP Europe amd Mike Bullock, Enventure Global

Sponsored by **ExxonMobil**

Winner: **Shell International E&P – 'Expandable Tubulars and MonoDiameter™ Technology'**

In the early 1990s, Shell began investigating the possibility of expanding oil field tubulars downhole. The company started with experiments to expand casing, but was initially unsuccessful due to excessive expansion forces. Expansion of tubulars with longitudinal slots was found to require much lower forces, and the development of Expandable Sand Screens™ was progressed rapidly.

Shell reverted to casing expansion and people soon realised its enormous potential for well construction – drilling deeper and cheaper with the ultimate promise of unlocking reserves that are out of reach with conventional technologies. The exponential uptake of expandable technology is predominantly based on specific applications in difficult wells. A second exponential surge is expected when the technology will be used in the standard well designs.

Drilling wells with an unlimited amount of casings has always been a dream of well engineers. In practical terms, this can only be done if each casing has the same size as the previous one. MonoDiameter™ technology is claimed to do exactly that. Because the surface casing is thus as small as the completion liner, these wells can be drilled with smaller drilling rigs. Especially offshore, where day rates of $400,000 are not uncommon. This can result in huge savings.

Three major elements have been crucial in achieving the rapid successes of expandable tubulars – the first was the simultaneous execution of theoretical modelling and physical experiments. The other two major elements were the setting up of two competing joint ventures with the service industry, and the introduction of a Global Implementation Team to introduce the technology in Shell's operating units.

international platinum

Sponsored by **Total**

Winner: **Shell UK Exploration & Production – 'Brent Alpha Redevelopment Project'**

Highly commended: **Heriot Watt University–Institute of Petroleum – 'Providing Masters Courses and Research for Yukos'**

In 2001 Shell UK Exploration & Production was faced with the prospect of having to cease production from its 25-year-old Brent Alpha platform, one of four platforms in the Brent gas field located in the northern North Sea, 113 miles north-east of Lerwick in the Shetland Islands. The platform faced similar challenges to many others in the industry – declining production and high operating costs, as well as increasingly demanding company standards and societal expectations.

Fresh thinking was called for and Shell Expro rose to the challenge with the Brent Alpha Redevelopment Project – a project that reduces risk levels on the platform while improving its environmental performance and reducing its operating costs by 75% (from £14mn to £3.5mn/y). The project has also increased field recovery by 16mn boe and extended the platform life until at least 2010. It has been enabled by the application of new technologies and by new ways of working.

The fresh approach didn't stop with the development of the concept, but carried through into the project execution phase. Over 550,000 man-hours of work were completed without any lost time injuries and without any environmental incidents. In addition, an innovative workforce charity incentive scheme raised more than £46,000 for community charities in England and Scotland.

Alistair Hope (Project Manager and Mandy Hirst (Project Services Team Leader), Shell UK, collect their award

Highly commended

In addition to the seven winners, the judges also Highly Commended Heriot Watt University–Institute of Petroleum Engineering for 'Providing Masters Courses and Research for Yukos', submitted under the International Platinum category.

The RAE 5* rated Institute of Petroleum Engineering is claimed to be unique in UK academia, applying unparalleled in-house multidisciplinary capability to the challenges of maximising hydrocarbon recovery through improved reservoir characterisation and management. The Institute excels in the provision of lifelong learning for the petroleum industry's professionals through Masters and short courses.

The Institute has established a Masters programme in partnership with Yukos and Tomsk Polytechnic University in Russia. The 12-month programme, taught and examined in English, is delivered on campus by both Heriot-Watt and Tomsk University staff, to young Yukos employees. On completion, graduates are granted internationally recognised diplomas, enabling them to potentially work with any oil company worldwide. Some 45 students graduated in September 2002 at a well-publicised ceremony in Moscow, and the same number is expected in 2003.

Yukos has further endorsed the success of the alliance by funding the extension of the Tomsk Centre to include a Masters degree in Reservoir Evaluation and Management, and has commissioned a new degree in Oil and Gas Technology, with both courses each generating 15 students. The latter is a joint development by the Institute of Petroleum Engineering and the School of Engineering and Physical Sciences at Heriot-Watt University, with advice regarding content from Yukos staff.

technology award

Presented by Jim Kent, Vice President, General Manager, Hewlett Packard Services for UK and Ireland to Dr D K Tuli, Indian Oil Corporation

Sponsored by Hewlett Packard
Winner: Indian Oil Corporation – 'OiliVorous-S: Technology for the Disposal of Oily Sludge'

The safe disposal of oily sludge generated in storage tanks and effluent treatment basins is a nagging problem in the oil industry. Realising the need for an environmentally safe and cost effective solution to this problem, IOCL, TERI and the Energy & Resources Institute jointly developed 'OiliVorous–S' technology for the disposal of oily sludge. The technology comprises five selected microbes that effectively biodegrade paraffins, iso-paraffins, nephthenes, condensed aromatics and sulphur compounds – the main constituents of hazardous oily sludge.

Field trials of OiliVorous–S were conducted at various IOCL refineries. Successful completion of the field trials established that the technology is a safe, practical, cost effective and viable solution to the problem of oily sludge disposal in the hydrocarbon industry. Based on these field trials, IOCL is progressing with the bioremediation of hazardous oily sludge in various units of the company.

OiliVorous–S technology not only offers a solution to the disposal problem of oily sludge, but it is also now being widely employed to bioremediate contaminated soil, tackle oil spills on land and also to dispose of accumulated sludge in both upstream and downstream sectors of oil industry.

safety award

Marcos Tucherman, HSE Superintendent (right) collects the award on behalf of Comgas from Roger Patey, Business Improvement Director, Shell UK Expro

Sponsored by Shell
Winner: Comgás (Companhia de Gas de Sao Paulo) – 'Comgás Safety Performance'

Prior to privatisation in 1999, Comgás observed only the most basic safety rules required by law. Investment in this area was not part of the company's plans or targets. This attitude affected staff performance, and consequently often resulted in incidents, which on occasion amounted to as many as 30 a month.

Four years later, privatisation has presented a real revolution in the company. In parallel to development of a consistent management plan focused on safety, health and environment, employees were asked to take part in the process. As a result, Comgás has completed more than 1,200 days without lost time injuries. The company aims to constantly maintain this high standard, ensuring that individual employees do not become complacent as a result of their current good safety performance record.

The system is based on the following thematic blocks:

- Commitment and leadership from the company's directorate
- Strategic policies and objectives
- Organisation, resources and documentation
- Evaluation and administration of risks in terms of safety, health and environment
- Planning
- Implementation
- Monitoring
- Periodic auditing
- System review (once a year)

Comgás believes in motivating and training staff. Thanks to clear and firm rules its employees are aware of the company policy and observe safety, health and environment guidelines, creating a safe working environment.

outstanding individual achievement award

To a standing ovation Vicky Robinson receives her Outstanding Achievement Award from John Mumford, OBE, EI Council Member, for the project 'Beyond Petroleum and Blessed Pupils' and below, more congratualations...

The 2003 IP Awards ceremony also included an Outstanding Individual Achievement Award – won by Vicky Robinson, BP Tanzania, for the 'Beyond Petroleum and Blessed Pupils' project submitted under the Community Inititative category.

The Blessed Pupils project is a community initiative to look after at least 20 orphans every year. The majority of these orphans have lost both parents due to HIV/AIDS and are in need of school uniforms, school fees and exercise books. Vicky Robinson has to make sure that these pupils attend classes and perform well in their studies.

She explains that education is the key to alleviating poverty and building a healthy and successful society. Helping these orphans is very important to her personally but, of course, also to the community. It is for those people who have the advantages of working for BP to offer help to those that do not.

The project also shows that BP is active in the community and represents hope and change for those stuck in the cycle of poverty. A company is not separate from the community but a part of it and, as such, has a responsibility to try to uplift those sectors that cannot help themselves.

The Blessed Pupils project is also involved in promoting public awareness of the plight of many disadvantaged groups, such as the disabled, the elderly, drug addicts and street children, as well as creating an awareness of HIV/AIDS in the community.

A collection for the project was held after the event. See p39 for more details.

Congratulations all round

After the Awards Ceremony, the Energy Institute's Chief Executive, Louise Kingham, commented: 'The EI, together with all involved in its creation and development over the past four years, is delighted to host this event which has gone from strength to strength. These awards remind us that innovation and excellence are the result of the actions of individuals, whether they act independently or collectively. We are delighted for this year's winners and our congratulations also extend to all the nominees.' ●

*** The Welcome Reception was sponsored by BG Group; the Winners Reception by Eni.**

If you would like to find out more about next year's Awards (which will be renamed to EI Awards) and other events, or how to enter a project for the EI Awards 2004, please contact Laura Viscione, EI Events Department –
T: +44 (0)20 7467 7174;
e: **lviscione@energyinst.org.uk**

Oil field mega projects 2004

The future shape and prosperity of the oil industry is determined by the mega projects – those with reserves of over 500mn boe and the potential to produce over 100,000 b/d of oil. Here, *Chris Skrebowski* tabulates and analyses all the mega projects, as well as the key discoveries that could become mega projects at some later date.

This year's listing has been expanded to include all the discoveries of over 500mn boe that are likely to become mega projects but have not yet reached the point of project sanction. Where projects seem certain to be sanctioned they have been included under the most likely start-up year. Those where the uncertainty is greater, or the production date is unknown, have been listed as 'potential projects'.

Examination of our mega projects database shows that, on average, from first discovery to first production is about six years. Where the project time is significantly shortened it is usually because there is some existing infrastructure that can be used in whole or in part. In contrast, where there is an extended delay the underlying cause is either political (Russia, Caspian), challenges in getting egress for production flows (Caspian), or the challenging economics of the production (heavy oil, tar sands).

In sharp contrast to gas, where there are large volumes of stranded reserves, there is a ready market for additional oil flows. The days of large oil companies having substantial reserves banks are largely over. This means that any substantial finds will become development projects in a very limited time, unless actively inhibited by politics or access.

Offshore domination

The listing is overwhelmingly dominated by offshore projects. For onshore projects production builds progressively as wells are drilled or gathering stations installed. In sharp contrast, most offshore projects are pre-drilled – which means that peak production flows are achieved rapidly and are largely determined by the capacity of the facilities. Companies aim to maintain flows from developments close to peak capacity for as long as possible by linking in new accumulations as the original accumulation starts to deplete. A perfect example of this is the Girassol facilities offshore Angola, where Total has just starting flowing the Jasmin field through the Girassol facilities to compensate for the decline from the Girassol field (see p41).

Over the last year (2003) seven mega projects have been brought onstream, with two more due to flow by the end of the year. As seven of the fields were offshore, most of the peak capacity of 1.2mn b/d should be achieved by 2004. In the course of the next 12 months (2004) a further 11 mega projects are due onstream. As most of them are offshore projects it means that most of the peak capacity of 2mn b/d will be flowing by 2005.

New capacity

The year 2005 continues to be the peak year for new mega projects coming onstream. Some 18 projects with a potential peak capacity of 3mn b/d are due onstream in 2005. For 2006 the pace of development eases back a little to 11 projects, with a capacity of around 2mn b/d.

Undoubtedly there will be project slippage – it already looks virtually inevitable that Kashagan will slip into 2007. However, the bottom line is that between 2003 and early 2007 some 8mn b/d of new capacity will have been brought onstream to meet global oil demand growth and to offset the decline in oil production from those areas that are already in decline.

Currently 21.3mn b/d or around a third of the world's oil production is already in decline (see *Petroleum Review* August 2003), the best estimate of the likely decline rate going forward is about 4%, made up of a typical onshore decline rate of around 3% and an offshore one of around 5%. On the basis of a 4% decline rate for one third of the world's production, global capacity declines by over 1mn b/d each year. Global demand growth is once again expanding at over 1mn b/d. (the IEA's latest estimate is for oil demand of 78.6mn b/d in 2003 and 79.6mn b/d in 2004. Demand in 2002 was 77.3mn b/d).

As a rough calculation, by early 2007 production capacity will have declined by 3-4mn b/d (2004–2006), offset by the 8mn b/d of new capacity – giving up to 4mn b/d of new capacity to meet demand growth of around 3mn b/d. However, this is before the additional capacity created from the development of all the smaller accumulations and the expansion of production in existing fields. In short, supplying global oil demand up to 2007 appears to be well covered and, depending on the timing of new capacity and economic conditions, there may even be periods of relative price weakness.

Problematic future

If we look beyond 2007, however, the outlook becomes rather more problematic. Only three mega projects are so far known for 2007 and a further three for 2008. For 2009 and 2010 only the later stages of existing projects are currently known about. Consequently, the volumes of new production for this period are well below likely requirements.

Even if the normal mega project development period of around six years was foreshortened to four years a mega project sanctioned now would be unlikely to be onstream by 2008. There are clearly enough known developments – listed as the 23 potential developments – to plug the gap. However, of these 23 developments 11 are in Opec countries and 10 in Russia, leaving just Shell's Great White discovery in the Gulf of Mexico and PetroVietnam's block 09-03 discovery in the Cuu Long Basin as yet-to-be sanctioned non-Opec, non-FSU projects.

Project	Location	Operator	Oil Peak Flows (kb/d)	Gas Peak Flows mn cf/d	Reserves mn/b	Partners and shareholdings
Onstream 2003						
Amenam/Kpono	Nigeria	Total	125 (04)			Elf Nigeria 30.4%, NNPC ??, Mobil Nigeria ??
Bijupura-Salema	Brazil	Shell	70 (03)		170 boe	Shell 80%, Petrobras 20%
Doba fields	Chad onshore	ExxonMobil	250		1000	ExxonMobil 40%, Petronas 35%, ChevronTexaco 25%
Grane	Norway	ExxonMobil	200 (05)			ExxonMobil 26%
Karachaganak PhII	Kazakhstan (onshore)	Eni and BG	200 (04)	1,400	2,400 (liqs)	Eni 32.5%, British Gas 32.5%, ChevronTexaco 20%, Lukoil 15%
Muskeg River (Tarsand)	Canada Athabasca	Shell	130 (03)			Shell Canada 60%, Chevron Canada 20%, Western Oil Sands 20%
Nakika	GoM	Shell	100	425	300 boe	Shell 50%, BP 50%
Soroush/Nowruz	Iran expansion	Shell	130			
Zafiro S'th'n, Exp Area	Equatorial Guinea	ExxonMobil	110		150	ExxonMobil(MEG) 71.25%, Devon Energy 23.75%, Equat Guinea Govt 5%
Onstream 2004						
Albacora Leste	Brazil	Petrobras	180 (09)		1507 boe	Petrobras 90%, Repsol 10%
Banyu Urip (Cepu block)	Indonesia Offshore	ExxonMobil	165		2000 in block	ExxonMobil 90%
Bayu-Undan Phase1 (liqds)	ZOCA	ConocoPhillips	200			ConocoPhillips 63%,
Bonga (OML 118)	Nigeria	Shell	225	170	600	Shell 55%, ExxonMobil 20%, TFE 12.5%, ENI 12.5%
Caofedian	China Bohai Gulf	Kerr McGee	100			Kerr McGee
Elephant NC-174	Libya onshore	Eni	150 (06)		760	Libya's NOC 50%, Eni 33.34%,Korean Consortium 16.66%
Kizomba A	Angola	ExxonMobil	250		1000 boe	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marco Polo	GoM	Anadarko	100		180	Anadarko??
Marlim Sul II	Brazil	Petrobras	180		2679 boe (tot)	Petrobras 100%
Priobskoye	Russia Siberia	Yukos	550		4000	
Roncador II	Brazil	Petrobras	140 (08)		2000 boe (tot)	Petrobras 100%
Onstream 2005						
ACG magastructure	Azerbaijan	BP	1000 (11)		5300	ExxonMobil 8%
Barracuda-Caratinga	Brazil	Petrobras	273 (06)		1778 boe	Petrobras 100%
Bonga South	Nigeria	Shell	250		1000	Shell 55%, ExxonMobil 20%, TFE 12.5%, ENI 12.5%
Corocoro Phase 1	Venezuela offshore	ConocoPhillips	50		240	ConocoPhillips 50%, PDVSA 50%
Erha	Nigeria	ExxonMobil	150		500	ExxonMobil 56.25%, Shell 43.75%
Frade	Brazil	ChevronTexaco	110 (05)		836 boe	ChevronTexaco?? Petrobras??
Greater Angostura Ph I	Trinidad	BHP Billiton	80		up to 300	BHP Billiton 45%, TotalFinaElf 30%, Talisman Energy 25%
Holstein	GoM	BP	100	290	500-1000 boe	BP 50%, Shell 50%
Jubarte+Cachalote?	Brazil B60 Santos	Petrobras	60+50?		600+300? boe	
Mad Dog	GoM	BP	100	290	up to 800 b	BP 63.56%, Unocal 25%, BHP 11.44% ??
Marlim Leste	Brazil	Petrobras	100 (07)		?	Petrobras 100%
NEAD project	NE Abu Dhabi	Adnoc	110			
Prirazlomnoye	Russia Siberia	Gazprom/Rosneft	150 (10)		600	
Roncador III	Brazil	Petrobras	145 (08)		2000 boe (tot)	Petrobras 100%
Sakhalin I	Russian Far East	ExxonMobil	250		2300	ExxonMobil 30%, SOGDC 30%, ONGC 20%, Russian Co's 20%
Salym fields-W,Upp,Vade	Khanty-Mansiisk	Shell/Evikhon	120 (09)		600	Salym Petroleum Development NV (SPD) 50% Shell, 50% OAO Evikhon $1billion project
Thunder Horse (inc. Nth)	GoM	BP	250	200	1500 boe	BP 75%, ExxonMobil 25%
White Rose	Eastern Canada	Husky Oil	100		230	Husky Oil
Onstream 2006						
Atlantis	GoM	BP	150		675boe+200b	BP 56%, BHP 44%
Agbami	Nigeria	ChevronTexaco	225		1000	ChevronTexaco 59%, Statoil 15% ??
Benguela-Belize (BBLT1)	Angola	ChevronTexaco	100		400	ChevronTexaco 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9%
Bu Hasa development proj.	Abu Dhabi	Adco	250			
Buzzard	UKCS	Encana	180 (07)		400	Encana 43%, Intrepid Energy 30%, BG Group 22%, Edinburgh Oil & Gas 5%
Dalia	Angola	Total	240		1600	TotalFina Elf 40%, BP 16.67 %, Statoil 13.33%, ExxonMobil 20%
Enfield	Australia NW Shelf	Woodside	100		363	Woodside Petroleum 100%
Kashagan Ph1	Kazakh Caspian	Agip (Eni)	450	1,500	9,000	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33%
Kizomba B	Angola	ExxonMobil	250		1000	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marlim Sul III	Brazil	Petrobras	100 (07)		2679 boe (tot)	Petrobras 100%
Tengiz expansion*	Kazakhstan	ChevronTexaco	200 to 450		7,000	ChevronTexaco 50%, ExxonMobil 25%, KazMunaiGaz 20%, LukArco 5%

Future oilfield projects with a peak production capacity of over 100,000 b/d

continued overleaf...

Project	Location	Operator	Oil Peak Flows (kb/d)	Gas Peak Flows mn cf/d	Reserves mn/b	Partners and shareholdings
Onstream 2007						
Lobito-Tombuco (BBLT 2)	Angola	ChevronTexaco	100 (09)		400	ChevronTexaco 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9%
Platina/Plutonio	Angola	BP	220		800	BP 50%, Shell 50%
Tahiti	GoM	ChevronTexaco	150?		700mn boe	ChevronTexaco 58%, Encana 25%,Shell 17%
Onstream 2008						
Kizomba C	Angola	ExxonMobil	250		1000	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marlim Sul IV	Brazil	Petrobras	120 (07)		2679 boe (tot)	Petrobras 100%
Kashagan Ph2	Kazakh Caspian	Agip (Eni)	900	1,500	9,000	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33%
Onstream 2009						
Karachaganak Ph III & IV	Kazakhstan					
Onstream 2010						
Kashagan Ph3	Kazakh Caspian	Agip (Eni)	1,200	1,500	9,000	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33%
Potential Projects						
Ahwaz Bangestan Devs	onshore Iran	NIOC/?	350			
Akpo	Deepwater Nigeria	S. Atlantic Pet.			625 boe	
Arash	Iran in Gulf	NIOC			683 boe	
Azadegan	onshore Iran	NIOC/?	100		2.5-3.5bn b	
Block 09-03	Vietnam Cuu Long Bas	Petrovietnam	100+?		300-400	
Ghawar Haradh Phase 2	Saudi Arabia onshore	Saudi Aramco	300			
Great White	GoM	Shell			500 boe	
Kharyaga	Russia Siberia	Total PSA			5200	
Khvalynskoye	Russian Caspian	Lukoil			627 boe	
Kirkuk Khurmala Dome Dev.	Iraq onshore	NOC	100			
Kushk	Iran	NIOC			1,000 boe	
Lungu	China Tarim Basin	Petrochina			500	
Majnoon	Iraq onshore	SOC	360			
Northern Fields Project	Kuwait	KOC/?	400			
Northern Territories 4flds	Russia Siberia	ConocoPhillips			1000	
Qatif field expansion	Saudi Arabia	Saudi Aramco	500			
Talanskoye	Russia Siberia	Being auctioned			832	
Val Gamburtsev	Russia Siberia	Yukos/Sibneft			600	
Vankorskoye	Russia Siberia	Shell/TFE PSA			900	
Verkhnechonsknoye	Eastern Siberia	TNK-BP?			1500	
Yuri Korchagin	Russian Caspian	Lukoil			879 boe	
Yuzhno-Shapinskoye	Russia Siberia	SeverTek			500	Lukoil Fortum
West Qurna Phase 2	Iraq onshore	SOC	650			

Future oilfield projects with a peak production capacity of over 100,000 b/d

Whether this skewing of future projects to Russia/FSU and Opec is seen as a curiosity or a concern largely depends on the degree to which western interests coincide with those of Russia and Opec. To date Opec has tended to favour prices rather higher than than western interests would prefer while the importance of oil exports to the Russian and FSU economies would suggest that they too would favour higher prices.

In terms of future production capacity the largest single unknown is the speed at which Iraq's production capacity can be restored and then expanded. The potential is certainly there (see *Petroleum Review*, July 2003) but the rate at which it can be developed is currently unknowable.

Although it is too early to be wholly certain there is mounting evidence that the discovery rate for major oil fields with reserves of over 500mn boe has fallen dramatically over recent years. IHS Energy, on a map of recent discoveries it supplies to its clients, records 28 discoveries of over 500mn boe in the three years 2000, 2001 and 2002. However, 16 of the discoveries were in 2000, eight in 2001 and just three in 2002. Broken down by discovery type this gives:

- 2000: 6 oil/gas finds, 7 gas/condensate finds, 3 gas finds;
- 2001: 2 oil/gas finds, 4 gas/condensate finds and 2 gas finds;
- 2002: 2 oil/gas finds (Shell's Great White and Petrobras' Jubarte) and 1 gas find.

This rapid decline in recent large discoveries may the explanation for why there are so few mega projects six years later, ie 2007-2008. A lack of recent discovery has also been seen in Russia, where IHS Energy records reserves replacement ratios of 17% in the last five years and 14% in the last ten years. Even Opec seems to be having difficulty replacing reserves with a replacement ratio of just 18.2% in 2002 (see *Petroleum Review*, November 2003).

The conclusion to be drawn appears to be that for the next four years a flood of new production is set to hit the market. Whether the volume and timing is of a magnitude that significantly depresses prices remains to be seen and will largely depend on whether existing flows are maintained and whether the sort of unpredictable events such as the production restrictions seen in Venezuela, Iraq and Nigeria over the last 12 months remain a feature of the market ●

While every effort has been made to esure that the data in the table is correct, if readers are able to fill in gaps or have better information the Editor would be very please to hear from them. Please contact: **cs@energyinst.org.uk**

Powering up with gas and coal

Thailand's economic recovery has increased demand for oil, natural gas and petroleum products during the past 18 months to levels last seen in the mid-1990s, writes *David Hayes*. A sharp increase in the number of vehicles crowding the country's roads has helped boost consumption growth figures for petroleum products, while rising electricity use has helped lift overall consumption of local and imported natural gas – most of which is used for power generation.

According to official figures Thailand's energy consumption bill in 2002 was about 780bn Baht, or $19.5bn. Energy imports, mainly oil and natural gas, cost more than 300bn Baht, or 37.5% of the total bill. In spite of efforts to increase domestic energy production, Thailand's energy import bill will continue to grow unless new domestic hydrocarbon resources are discovered. The government forecasts that the total national energy bill will increase almost two-fold to reach 2,100bn Baht over the next 15 years if energy consumption growth continues at its present rate.

Thailand's proven oil reserves are estimated at 580mn barrels, while gas reserves are estimated at 13.3tn cf. Recoverable coal reserves, mostly lignite, are estimated at about 2.2bn tonnes. Other resources include hydropower, although these are smaller and mostly developed. Renewable energy also offers development potential and could attract greater government support to help reduce the growing energy import bill.

Oil consumption in 2002 was 821,000 b/d, a 4.6% increase compared with 785,000 b/d the previous year. Domestic crude oil production was 127,000 b/d, accounting for 15.5% of consumption. The balance was imported. Gas consumption rose at a higher rate than oil in 2002, reaching 2,475 mn cf/d, up 8% compared with 2,291mn cf/d the previous year. Some 78% of total gas consumption was for power generation, the remaining gas supplies being used by industrial customers.

Energy demand has grown by almost 3% during the past two years. Based on current economic growth projections, PTT – Thailand's largest oil refiner and sole supplier of natural gas – expects total energy consumption to grow 5% in 2003, rising to 6% in 2004. 'Thailand is recovering from the economic crisis,' commented a PTT executive. 'Electricity generation and vehicle transport fuel demand are driving energy demand growth. Before the financial crisis in 1997 energy consumption was growing by 7% or 8% annually, even by double digits some years.'

According to government figures about 500,000 new cars came onto Thailand's roads in 2002. With interest rates in Thailand at a record low, a further 500,000 new cars are expected to come onto the roads in 2003. The rapid increase in vehicle numbers has led to a strong increase in demand for gasoline. Petroleum sales countrywide are about

40bn litres a day through a national network of more than 10,000 service stations. However, diesel production in Thailand is in surplus and consequently has to be exported.

Thailand's economic recovery has lifted energy demand. After growing by almost 5% in 2002, the economy is expected to grow 5% to 6% in 2003 in spite of the impact of the severe acute respiratory syndrome (SARS) epidemic in Asia earlier in the year. Exports rose 19% in 1H2003. As a result a significant share of growing electricity consumption is by industrial consumers.

Refining overcapacity

Thailand has seven refineries, with a total refining capacity of 1,012,000 b/d. At present the domestic refining industry is 19% overcapacity.

PTT is the nation's largest refiner, with shareholdings in four refineries that are capable of refining a total of 635,000 b/d – equivalent to 63.5% of Thailand's total refining capacity. PTT's sales of oil products grew by 9.4% in 2002, giving the company the major share of Thailand's market for the tenth consecutive year.

PTT has a 49.99% shareholding in the 220,000 b/d Thai Oil Company (TOC) refinery and a 24.29% interest in the 120,000 b/d Bangchak refinery. It also holds a 36% shareholding in the 145,000 b/d Rayong refinery joint venture with Shell and a 36% stake in the 150,000 b/d Star refinery joint venture with Caltex.

Based on its shareholdings PTT owns 400,000 b/d of refining capacity and has a 45% share of the domestic market. The company exports about 30% of its daily production. China is the largest overseas market, taking 50% of PTT's exports. The rest are shipped to Vietnam and other countries in Southeast Asia.

Thailand's three other refineries are the Thailand Petrochemical Industries' 215,000 b/d complex, the 145,000 b/d Esso refinery and a small 17,000 b/d condensate splitter.

In spite of rising domestic petroleum sales, several refineries continue to face debt problems. Integrated refinery management is one solution being used to reduce these debts.

In 1999 the Rayong refinery and Star refinery set up Alliance Refining Co (ARC) to provide integrated management support and use the resulting operational savings to reduce their individual debt problems. ARC recently announced it has realised about $200mn in savings for Rayong and Star since its establishment. ARC has assisted the refineries in improving their gasoline blending efficiency, in reducing feedstock and operating costs, and in upgrading fuel oil production to diesel. The two refineries currently refine about 255,000 b/d and operate at 85% of their combined 295,000 b/d refining capacity.

Although no further expansion of Thailand's oil refining sector is expected while the current refining overcapacity remains, changes in refinery ownership are possible. More than one foreign refinery investor is thought to be interested in selling shareholdings. Sinochem of China, with which PTT enjoys good relations, is considered the most likely new investor.

In fact, the government has been discussing a proposal to turn Thailand into a regional oil refining and transportation hub. One possibility includes the creation of a bonded refining zone to attract export orientated refineries for which the main markets would include cities in southern and central China, which are geographically closer to Thailand than the east coast of China where most of the mainland's refining capacity is located.

Another related proposal would involve construction of an oil pipeline across the Isthmus of Kra from the Andaman Sea to the Gulf of Thailand, with oil handling facilities at either end, which would allow oil shipments from the Middle East to East Asia to bypass the crowded Straits of Malacca.

Reducing energy import growth

Meanwhile, the government is looking to encourage energy conservation and renewable energy development to reduce the energy import growth rate. Currently Thailand's energy consumption is growing at a ratio of 1.4:1 in relation to the economic growth rate. The government wants to reduce this to a ratio of 1:1 by 2007.

Thailand's previously modest plans to develop renewable energy for power generation are also being expanded to cut down energy import growth. The government has announced that it wants to increase the share of renewable energy from 0.5% of commercial primary energy, or 265,000 tonnes of crude oil equivalent (ktoe) in 2002, to 8%, or 6.54mn ktoe, by 2011. At the same time legislation is planned that will require developers of new power stations to build facilities so that at least 4% of their new power plant facilities are generated by renewable energy. The proposal is designed to deflect criticism from environmentalists that Thailand is lagging behind other Asian countries in promoting renewable energy.

Greenpeace activists recently complained that plans to expand the country's power generation capacity from 22,600 MW at present to 52,000 MW in 2020 rely mainly on building coal-fired power plants to burn imported coal and gas-fired power stations. Previously the government had forecast that by 2020 just 560 MW of installed generating capacity would be fuelled by renewable energy, accounting for just 1% of Thailand's forecast power generation capacity.

Apart from requiring large power plant developers to incorporate renewable energy schemes in their programmes, new legislation is being drafted that will permit villages with renewable energy sources such as farm waste to produce and sell electricity to the government. Under the proposed law, local communities will be allowed to build power plants up to 3 MW installed capacity. Most small power plants are expected to use pig farm waste and biomass from rice padi production and sugar mill operations.

Meanwhile, Thailand's economic upturn has caused an increase in demand for natural gas, particularly for power generation, as energy demand continues to grow throughout the Kingdom. Gas consumption is expected to continue growing in the future as the government will maintain its policy of substituting imported oil with local and imported natural gas.

Rising gas demand

Following its 2001 listing on the Stock Exchange of Thailand, the formerly state-run PTT remains responsible for the supply and sale of all natural gas in Thailand. Planning is currently underway to expand the supply of domestically produced gas, including development of reserves owned jointly with Malaysia in the south of the Gulf of Thailand. In addition, imports of gas from neighbouring Myanmar will grow once proposals to increase the transmission capacity of PTT's pipeline from the Thai border with Myanmar to the central region of Thailand are implemented.

In 2002 PTT's procurement of natural gas rose 8.7% to 2,494mn cf/d, compared with 2,294mn cf/d the previous year. Gas imports from Myanmar accounted for 58% of the increased gas purchases in 2002. PTT purchased 1,876mn cf/d of locally produced gas in 2002, along with 618mn cf/d of gas imported from Myanmar, which now accounts for almost 25% of Thailand's gas supplies. Myanmar's offshore Yadana field supplied 418mn cf/d in 2002, while the offshore Yetagun field supplied almost 200mn cf/d. Unocal is

Thailand's largest gas producer supplying 830mn cf/d from various offshore gas fields in the Gulf of Thailand, accounting for 33.3% of gas supplies in 2002.

Important gas fields operated by other companies include the Bongkot field in the south of the Gulf of Thailand, which supplied PTT with 530mn cf/d in 2002, representing 21.3% of total gas supplies, while the nearby Pailin field supplied 235mn cf/d, accounting for 9.4% of gas supplies. Elsewhere in the Gulf of Thailand the Tantawan and Benchamas gas fields produced a combined total of 225mn cf/d, equivalent to 9% of supplies. Thailand's sole onshore gas field is the Nam Phong field in northeast Thailand, which produced 56mn cf/d in 2002.

Increased gas procurement in 2002 helped PTT increase gas sales to both the power generation and industrial sectors as more gas was burned as a substitute for fuel oil. Gas sales reached 2,475 mn cf/d in 2002, up 8% compared with 2,291mn cf/d the previous year. According to PTT some 78.2% of total gas sales were to the Electricity Generating Authority of Thailand (EGAT), independent power producers (IPPs) and small power producers (SPPs). State-run EGAT bought 1,074mn cf/d in 2002, virtually unchanged from the previous year, while while IPP plants bought 486mn cf/d, up 35% compared with 360mn cf/d in 2001 due to the recent increase in IPP generation capacity. SSP plants bought 375mn cf/d, an increase of 7.4%. Apart from gas sales to power plants PTT supplied 342mn cf/d as feedstock to four gas separation plants the company owns itself, accounting for 13.8% of sales.

In 2002 PTT supplied a further 198mn cf/d of gas to the industrial sector, representing 8% of total gas sales, including gas for cogeneration plants, fuel for NGV vehicles and for piped distribution by PTT Natural Gas Distribution Company. Currently the company has about 155 industrial customers and 12 clients operating cogeneration facilities. PTT is looking to add about 50 more industrial customers by the end of 2004 as part of plans to convert industries using oil to burn gas.

PTT is forecasting a further 6% increase in gas sales in 2003, which are expected to reach about 2,620mn cf/d. With gas demand forecast to continue growing PTT will continue to upgrade and expand its transmission pipeline network to increase gas supplies to major gas consuming regions.

Industry reform

In addition to supplying almost 80% of its gas supplies to power companies for electricity generation, PTT's future gas supply business development could also be tied up with proposals under consideration by the government to restructure the electricity sector following EGAT's imminent privatisation. The government has appointed consultants to study EGAT's privatisation plans, including the issue of third-party access to the utility's transmission network.

Introducing third-party access to the power sector is likely to involve access being opened to gas transmission pipelines in the future. 'Government policy is third-party access, but we have not started yet as our gas pipeline capacity is fully used up,' commented the PTT executive. 'We think that gas industry reform will be in line with the result of the new electricity industry reform. If there is third-party access to EGAT's transmission network then there will be to PTT's gas pipelines too. It will depend on the EGAT privatisation study.'

Newcastle Student Chapter spreads the word

The new EI Student Chapter Chairman at Newcastle University, *Job Vazques*, got off to a flying start by helping out-going Chairman *Said Mazaheri* (see *Petroleum Review*, December 2003) host an 'Energy Industry Event' on 4 November 2003, at which speakers from a wide spectrum of the energy industry gave presentations and were available for Q&A sessions. All the speakers, as requested, had recently graduated and embarked on careers in the oil, gas and energy sector.

The first speaker was Craig Ashton, an Environmental Manager with British Nuclear Fuels Ltd. (BNFL), assisted by Alison Tulloch, an Environmental Advisor, who helped answer questions after the presentation. Craig outlined the wide range of job opportunities for some 120 graduates a year within BNFL – covering the decommissioning of redundant power stations to the design of new ones. In a wide-ranging talk he predicted a bright future for the nuclear sector because of carbon emission demands and the power needs of the future. As a result, he viewed BNFL as a secure job prospect for suitable graduates.

Craig was followed by Ross Sollazzi, a Design Physicist with the Engineering Business (EB) – a medium sized local company specialising in a range of cutting edge designs and machines, including undersea ploughs for oil pipelines, wave mats for sea calming, and various offshore module designs. Ross explained that he was directly involved with the development of wave/tidal powered generators that were currently undergoing tests off the Shetland Islands. He commented on the difference between student life and that in a commercial enterprise, where the results of your design work could not only be seen, but also had to perform. He saw a promising future in this area of the renewable energy.

The final speaker was Tom Thorogood, a Civil Engineer from Amec Wind Energy (formally Boarder Wind) – a company local to the University. Tom outlined his part in the local Blyth wind farm project as an illustration of the nature of his work. He then went on to discuss the attitude of various European governments to the use of wind energy and various initiatives to encourage uptake of this renewable form of energy. Tom also commented on some of the problems caused by regulation or lack of commitment, etc. He also explored the potential of a high voltage direct current European grid, using this to link wind farms in the North Sea, as a method to increase efficiency. Like the other speakers, Tom saw a bright future for his sector of the industry, but was not blinded to the potential difficulties facing it.

The event was well-attended, with over 40 student turning up to hear the speakers, ask questions and network. Of those who attended, a large number indicated a desire to joint the Energy Institute and take advantage of the advice and help that it can offer as they develop their careers in the industry.

Richard Maddison (left), Managing Director of Indus*, on behalf of the EI in his role as Chairman of the North East Branch, recently presented a certificate to Said Mazaheri (second from left) at Newcastle University in recognition of all his hard and enthusiastic work during his time as Chairman of the EI Student Chapter. The University's School of Marine Science & Technology was represented by Professor Tony Roskilly, Chair of Marine Engineering (second from right), aided by Job Vazquez (far right) the Chapter's new Chairman. Job is being sponsored by Spain's Science & Technology National Council (www.conacyt.mx)

Said, who is sponsored by the Iran Ministry of Energy, was both surprised and delighted to receive the certificate.

The amalgamation of the old Institute of Energy (InstE) and the Institute of Petroleum (IP) have given the new EI a broarder appeal, which Job aims to exploit in the months ahead by actively seeking members from other sectors of the industry. This process will prove doubly interesting to Job as he is already investigating how organisations deal with change as part of his PhD studies.

** Indus specialises in energy sector valuation and economic analysis.*

Hanging in there

Photo: Øyvind Hagen, Statoil

Despite Latin America's political upheavals there are plenty of upstream opportunities. *Maria Kielmas* reports on some recent developments in the region.

Production liners to be installed in one of the 260 wells drilled so far by the Sincor project, Venezuela. Statoil (15%), TotalFinaElf (47%) and PdVSA (38%) have invested $4.2bn in the heavy oil project. Onstream since March 2002, production is expected to plateau at 180,000 b/d.

ARGENTINA

Oil companies are maintaining varied levels of investment in Argentina despite the escalating arbitration disputes between the government and foreign investors. Repsol-YPF – which accounts for over half of the country's oil and gas production – announced in November 2003 that it will invest up to $6bn in its Argentine oil and gas operations, of which $3.5bn is destined for exploration in the Neuquén Basin and offshore the Santa Cruz, Tierra del Fuego, Rio Negro and Chubut provinces.

ChevronTexaco is to invest $150mn in Neuquén Basin exploration during 2004, while Vintage Petroleum will invest $84mn – some 37% of its total 2004 capital budget – in exploration in the San Jorge Basin. Meanwhile, local company Techint is to invest $750mn in the construction of a new gas pipeline between the northern province of Santa Fe and Bolivia. The remaining $250mn for the project will be financed by the Argentine Government.

This panorama is overshadowed by 62 separate claims registered by foreign investors in public utilities against the Argentine Government for breach of contract at the World Bank's arbitration tribunal under the International Convention for the Settlement of Investment Disputes (ICSID). The companies are suing for damages in the wake of the government's freezing of public service tariffs in January 2001 and its shifting of tariff denomination from US dollars to devalued pesos. The government faces claims at ICSID for over $20bn, in addition to lawsuits pending from overseas investors of $84.3bn of defaulted public sector bonds.

Under new legislation, the government has the power to renegotiate utility contracts. It is able to pre-determine tariffs, obligatory investments, quality of service, fines, and provision of supplies to low income groups. The new legislation conflicts with the existing constitution, which states that public service tariff renegotiations should be made through the regulatory agencies and public consultations. It also conflicts with over 40 bilateral investment treaties that successive Argentine governments have signed since the 1990s.

Foreign investors argue that without a tariff rise the energy infrastructure in the country will collapse. Gas production has risen 24.4% over the past year and a half, while proven gas reserves have fallen by 15%. The electricity system has reached the limit of its capacity. Wellhead gas prices are 45 cents/mn cf compared with a pre-devaluation level of $1.40/mn cf.

BOLIVIA

The ousting of former President Gonzalo Sánchez de Lozada in October 2003 in the wake of a month-long bloody uprising has left Bolivia's territorial integrity, as well as its hydrocarbons industries, in jeopardy. There is open discussion of the gas-rich southern Bolivian provinces splitting and forming closer relationships with Chile and Argentina, while indigenous leaders talk of the creation of a separate state.

The replacement government of President Carlos Mesa is committed to reforming hydrocarbons legislation, holding a referendum on gas exports and calling a constituent assembly to draft a new construction under which fresh elections can be held. As of mid-November 2003 local commentators believed that hydrocarbons legislation reform must come first, so that the new government can achieve a degree of

consensus from all political and social groups. They argue that once this new legislation has been agreed a referendum may be held on the nature of future gas exports; only afterwards could there be moves to elect the members of a constituent assembly.

Discussions for reforming Bolivia's hydrocarbons legislation have been underway for over two years. Representatives from both the governing coalition and opposition parties are seeking a significant rise in royalties paid by exploration companies – from 18% to 37%. Other proposals under debate include an obligation on companies to reinvest between 30% and 50% of their profits (whether gross or net is not stipulated) in new operations in the country. Central to hydrocarbons sector reform is the creation of a more powerful state oil company from what remains of Yacimientos Petroliferos Fiscales Bolivianos (YPFB) following various privatisations in the 1990s.

The overwhelming popular opposition to Bolivian gas exports and the subsequent stalling of the $6bn Pacific LNG project was the fruit of a massive campaign on the part of the left and indigenous leaders who used the gas project as a platform for their own agendas. The opposition campaign escalated from one about gas exports to protests about the cost of living, the minimum wage, pensions, the US-sponsored drug eradication programme, free trade, globalisation, and even the presence of US troops in Iraq.

Both the Chilean and Peruvian Governments had offered Bolivia similar terms for the lease of land to site an LNG export terminal. The shorter route through Chile proved to be more cost-effective and was favoured by the Pacific LNG consortium. However, given the popular opposition to this route, even the Chilean Government has discounted the LNG project being sited on its territory.

Potential markets for Bolivian gas are being squeezed. The US market will be supplied by Russian, Asian and even Peruvian gas ahead of Bolivia's. Meanwhile, Bolivia's main client, Brazil, has reduced its gas import needs from both Bolivia and Argentina following the discovery of a 14.2tn cf field in the offshore Campos Basin. Indeed, Brazil is even considering an LNG export project of its own to the US market.

COLOMBIA

Companies will be able to negotiate extensions to the production period of association contracts under proposals unveiled by the government in early August 2003. The newly-created regulator – Agencia Nacional de Hidrocarburos (ANH) – which has been modelled on the initial structure of its Brazilian counterpart, is drafting more favourable contract terms for new upstream investors. Although these are not expected to be announced until early 2004, they may include the possibility for investors to upgrade existing agreements to the new terms. ANH Director José Armando Zamora is in favour of a return to the old exploration concession system in Colombia. This was the norm up to the 1970s and did not involve state company participation.

The creation of the ANH was part of a broader restructuring of the state oil and gas sector, which included the transformation of state Ecopetrol into a 100% state-owned joint stock company, Ecopetrol, and a holding company for Ecopetrol's non-core assets, Promotora de Energía de Colombia. The changes transfer the responsibility of negotiating and supervising contracts with foreign and private sector investors to ANH, thus avoiding a conflict of interest whereby Ecopetrol was both judge and party to these contracts. In addition, national oil policy will be drafted by the ANH. State gas transmission company, Ecogas, which is 100%-owned by Ecopetrol, is to be privatised.

ECUADOR

The bidding for projects to increase oil production at five oil fields operated by state oil company Petroecuador opened in early November 2003. The Auca, Culebra-Yulebra, Lago Agrio and Shushufindi oil fields produce a total of 90,000 b/d and have a combined 870.5mn barrels in proven remaining reserves.

Industry interest should have been encouraged by the imminent commissioning of the new privately-operated oil pipeline, Oleoducto de Crudos Pesados (OCP), which aims to transport heavy crudes from the Oriente jungle areas to an export terminal on the Pacific coast. Petroecuador has also lowered transportation tariffs on the existing trans-Andean oil pipeline, SOTE. However, confusion about investment conditions has meant that industry interest is muted. The terms at present include a minimum 35% participation for the state, royalties ranging between 12% and 18.5%, and unresolved issues concerning environmental liabilities, taxes and local opposition to foreign oil companies.

Almost a decade after US-based lawyers acting on behalf of indigenous and the colonist communities in the

Photo: Walsh Environmental Scientists & Engineers

Canopy bridges along a rainforest pipeline in Ecuador – winner of the IP 2003 Environment Award (see p14).

Oriente initiated a lawsuit in US courts against Texaco for environmental damage during its 1972–1990 oil production period there, the case has opened in Ecuador. US judges, who threw out the case from US courts four times on grounds of jurisdiction, have alerted that if the now defendant ChevronTexaco loses the case and is fined by an Ecuadorian court, then that fine will be enforceable in the US.

MEXICO

Investor interest in bidding for gas exploration blocks in the Burgos Basin in northern Mexico has been slow to date. Repsol-YPF became the first company to be awarded a multiple service contract (CSM in the Spanish acronym) – a form of service contract – in the

Photo: Øyvind Hagen, Statoil

country's first gas exploration round.

The Spanish company, which pledged to invest $2.4bn, was the only bidder for the Reynosa-Monterrey block in the Burgos Basin. A consortium led by Petrobrás and which includes Japan's Teikoku Oil and local company D&S Petroleum was awarded the Cuervito block in Nuevo Leon state, pledging to invest $1.1bn, while Argentina's Techint, together with local company industrial Perforadora de Campeche, was awarded the Misión block and pledged to invest $1.035bn.

As of mid-November 2003 Pemex had received no bids for the Ricos block. A further three blocks in the Burgos Basin await award.

PERU

Perupetro, the Peruvian Government agency that promotes and negotiates upstream ventures, is offering 12 new exploration blocks for bid. Five of these are located in the Marañón and Ucayali Basins of the eastern jungle, two are on the Talara Basin continental shelf and two in the Trujillo Basin. In May 2003 the government finally gave approval to a reform to the royalty system. Companies now have two options – a royalty level dependant on production or one on profitability. In the first case the royalty starts at 5%, rising on a sliding scale to 20% for production over 100,000 b/d. In the second case royalties are linked to the 'R' factor, which depends on reported income and expenditure. An initial royalty of 5% applies up to an 'R' factor of 1.15 until cost recovery. After this an additional variable royalty ranging between 0% and 20% applies, according to revenue and costs incurred by the company.

The Camisea gas development project is seeking to fill a $225mn financial hole following the refusal by the US Export Import Bank to support a $214mn loan for the project. The Eximbank Board of Governors voted two to one to reject the loan on environmental grounds, following an intense international campaign against the project by advocacy groups. Other multilateral lenders, such as the InterAmerican Development Bank (IDB) and the Andean Development Fund (CAF), are still supporting the Camisea project with new loans. Pluspetrol, the operator of the Camisea gas field development, has asked Eximbank to reconsider its position.

VENEZUELA

The Venezuelan Government has been giving confusing messages about the future of all contracts in which state oil company PdVSA is involved. President Hugo Chávez ordered a review of all contracts in August 2003 in order to gain more favourable terms for the state. But he affirmed that contracts with foreign governments, especially those dealing with Orimulsion exports, will be respected. Subsequent events proved the opposite. The government suspended all oil shipments to the Dominican Republic because of an alleged conspiracy being hatched in the country to overthrow Chávez. By November 2003 Canadian, European and Asian buyers of Orimulsion were worried about their supplies after the Chávez Government decided to eliminate PdVSA's Orimulsion production subsidiary, Bitor.

There is little clarity either about current oil production levels. The government claimed in September 2003 that it was 3.3mn b/d, while the Paris-based International Energy Agency (IEA) reported that output was closer to 2.23mn b/d. Dissident PdVSA employees reported that the real production levels could be between 2.3mn b/d and 2.4mn b/d in November 2003. However, of this total, nearly 1mn b/d comes from foreign operators in the country.

PdVSA dismissed over one-third of its workforce, consisting of some 18,000 employees, during and immediately after an oil workers strike at the beginning of 2003. Those sacked included traders, reservoir engineers, production geologists and nearly all technical and IT staff. The company tried to replace these with foreign workers from other Opec countries, in particular Libya, Iran and Iraq. PdVSA executives have also travelled to the US in the hope of finding more oil companies prepared to work in Venezuela. The aim is to outsource PdVSA production operations that are no longer viable in the absence of qualified staff.

However, problems with the contracts being awarded to foreign companies are mounting. PdVSA has awarded exploration acreage to companies such as ChevronTexaco and ConocoPhillips in the offshore Caribbean known as Plataforma Deltana. Former PdVSA chief, Luis Giusti says that, although these contracts are strictly legal as they were signed with a recognised government, the process of awarding them has violated a number of positional provisions. A future government could revoke them.

Next year PdVSA aims to licence gas exploration acreage in the Gulf of Venezuela alongside the disputed maritime border with Colombia. Relations between Venezuela and Colombia are strained because of widespread allegations of President Chávez' support for insurgency groups in Colombia. ●

No quick fixes for US oil and gas

Regardless of any new energy policy initiatives, the US oil and gas scene is unlikely to see any significant easing of supply shortages in the coming year, writes *Judith Gurney*. This is especially true with regard to oil.

There are no foreseeable solutions to the continued long decline of domestic oil output. Production during 1H2003 was the lowest in 50 years, some 40% lower than its 1970 peak. Production of Alaskan oil – once the saviour of the US oil industry – is rapidly declining, with an output in 1H2003 some 50% of its 1998 peak.

There is no reason to believe that demand for oil or oil products – gasoline demand was unusually high last summer and into the autumn – will fall, given that the economy is apparently picking up. Crude imports, which has recently reached a record high, will probably continue to rise.

Enigma of natural gas

The unexpected fall in the price of natural gas last summer makes prediction here more difficult despite incontestable supply limits. For several decades the government has been strongly encouraging the use of natural gas as an efficient and environmentally beneficial fuel, especially for electricity generation, while blocking the development of known gas resources in untapped basins for environmental – and political – reasons. With high depletion rates in existing basins, production has been essentially flat for the past decade, despite new output from Gulf of Mexico deepwater fields and from coalbed methane (CBM) projects. Unlike crude imports, gas imports cannot be substantially increased in the short-term.

The behaviour of gas prices suggests uncertainty regarding gas demand. The dramatic increase in futures prices on the New York Mercantile Exchange (Nymex), which began in the autumn of 2002, was assumed to reflect permanently higher demand partly resulting from new gas-fuelled electricity generating plants. Prices continued to escalate during the following winter, rising from earlier levels of around $4mn/Btu to reach $6.44mn/Btu in June 2003. Then, within days of alarm over the threat of continued high prices expressed by Alan Greenspan, US Federal Reserve Chairman, and by Energy Secretary Spencer Abraham, prices began to fall – apparently in response to a US Energy Information Agency (EIA) report of unusually large injections of gas into underground storage. By late autumn prices had returned to the levels of 2002 before the dramatic increase, albeit higher than those in the same period in 2001.

Will prices rise to reach 'crisis' proportions again during this coming winter, reflecting strong demand in a tight supply situation? Some analysts believe they will, others don't. The EIA contends that gas demand will remain flat in 2004, with increased consumption by the industrial and commercial sectors cancelled out by lower demand from the electric power sector. Presumably this analysis reflects a belief that more energy-efficient industrial plants, and the migration of factories overseas, has resulted in lower electricity demand from these consumers. Many of the new gas-fired generating plants apparently face overcapacity.

The usual explanations for lower gas demand include a weak economy, abnormally mild weather conditions, and the fact that natural gas liquids can either be left in the gas stream, thus increasing the amount of gas available to the market, or removed to be sold separately when NGL prices are high. These factors are, to some extent, measurable. But there is less visibility concerning two other demand influences – dual-fuel capacity in customers (especially electricity generators, which some now consider to be the marginal consumers of natural gas and the setters of market-clearing prices) and speculation by gas marketers.

Easing of gas supplies

Short-term options are not good. Given the political clout of voters in California and Florida, it is unlikely that the current moratoria regarding the extraction of gas reserves believed to exist off the coasts of these states will be lifted in the foreseeable future.

Deep drilling in the shallow waters of permitted areas in the Gulf of Mexico, encouraged by tax relief, should lead to discoveries – but the risks and costs of deep drilling are such that few companies may be willing to get involved. Further ahead, an Alaska gas pipeline, if and when built, will bring considerable supply relief.

Focus on the Rocky Mountains

One option for long-term, and possibly near-term, gas supplies lies in the Rocky Mountain areas in the western US. The federal government owns vast areas here that it acquired largely through its 1803 Louisiana Purchase, from France, of 2.2mn sq km stretching from the Gulf of Mexico to the current Canadian border. (Although some of this acreage has been sold off, property deeds are often 'split', with the government retaining subsurface minerals rights on privately owned surface plots.) The government administers its holdings largely through its Bureau of Land Management (BLM) and its Forest Service.

The National Petroleum Council has estimated that there may be 69tn cf of gas under federal lands in the Rocky Mountains, which are either off-limits or under heavy restraints for use. These restrictions arise from the multiple-uses of the Rockies that include forestry, grazing, wildlife habitat, and recreation. These interests, which give rise to a host of environmental concerns, have resulted in a patchwork of barriers and regulations. Conditions of approval for access to federal lands and for gas exploration involve consideration of impact on air and water, as well as visual and sound effects. As Rocky Mountain gas basins are dominated by unconventional gas, primarily tight sands and CBM, impact on water supplies is a considerable concern. In some areas there are conflicting interests for other mineral rights, such as coal and potash.

Of primary importance for any gas exploration and production are restrictions regarding the construction of access roads. The Clinton administration established a 'roadless' rule, which restricts road building in large areas of the Rocky Mountains; the Bush administration has been working steadily to weaken this rule. It is able to do this, without Congressional assent, by issuing new regulations. The Bureau of Land Management has identified five Rocky Mountain areas as priorities for gas resources, including the Powder River Basin in northwest Wyoming and southeast Montana, which is said to be able to yield up to 40tn cf gas if fully developed. It believes that it can increase access to these gas reserves, and produce them, without compromising existing environmental laws. In 2002, the Bureau issued several new rules aimed at reducing barriers to access.

However, the administration's efforts

are sometimes stymied. While several federal judges in Wyoming, Idaho and Montana have ruled that the Clinton road-building restrictions are illegal, these decisions have been overturned in higher circuit courts. This may change following the passage by Congress, in early November, of a $29bn Natural Resources Bill, which contains a number of Republican-backed environmental waivers regarding road-building and access. The omnibus energy bill also expands the authority of the BLM regarding access to the Rockies.

Gas imports

There's been a lot said lately about the US as a potentially important market for LNG, given the domestic supply shortfall. There are now four working LNG terminals – one in Everett, Massachusetts; one in Lake Charles, Louisiana; one in Elba Island, Georgia; and one in Cove Point, Maryland. The latter facility was brought back into service last summer by Dominion Resources, after many years of closure, with a delivery in July by BP Energy from Trinidad and Tobago. All of these terminals have plans to expand.

More than 20 projects for new LNG import terminals in the US and Mexico have been mooted for both onshore and offshore sites. It seems certain that at least some of these will go ahead. Others will find the many federal and state constraints regarding the development of regasification capacity on safety and environmental grounds unacceptable. Some of the proposals, including ones by El Paso and Shell, have already been withdrawn.

A shortage of terminals isn't the only constraint on LNG imports. Gas price levels and their stability is another. Many LNG producers consider the US as a market that is attractive only when prices are high and when they have spare output over and above their commitments to long-term buyers elsewhere. Concern about price stability makes traders very reluctant to commit to long-term contracts and almost all current LNG imports are done under short-term or spot arrangements. When prices are low, only Trinidad and Tobago can provide LNG to the US at a profit.

In the long-term, more gas will probably be imported by pipeline from Canada. Although Canada's existing gas fields, like those in the US, are in decline, there are extensive untapped gas reserves in the northwest Canadian MacKenzie Delta. Development of these reserves is expected to begin soon following an agreement reached with Indian tribes regarding the route for the pipeline transport of MacKenzie gas to markets.

Water depth (metres)	Active leases	Approved application to drill	Active platforms
0 to 200	3,437	39,747	3,404
201 to 400	199	1,176	20
401 to 800	372	745	10
801 to 1,000	313	363	5
1,000 and above	3,275	893	8

Source: US Department of the Interior, Minerals Management Service

Table 1: Gulf of Mexico offshore activity, November 2003

Gulf of Mexico

But what of the Gulf of Mexico whose deepwaters were seen, not so long ago, as the answer to both oil and gas supply problems? Perhaps the most judicious reply is that the patient is well and bulletins are no longer being issued. Deepwater discoveries, which tend to be predominantly oil fields with sparse gas holdings, are coming onstream in accordance with timetables that fit the strategies of companies with widespread interests elsewhere.

Most projects which came into production this past year, and those which are scheduled for the coming year, are relatively small fields with estimated reserves of 100mn boe or less. A few are larger, ranging up to a possible 450mn barrels for BP's Mad Dog field. Many deepwater and less deep projects are producing, or will produce, through subsea attachments to existing platforms, so that the Minerals Management Service's (MMS) list of active platforms does not give an accurate picture of production. Some new projects are being developed with Spars.

Auctions for leases for offshore blocks continue to draw bidders and handsome sums, with interest split between blocks in ultra-deepwater and shallow waters believed to contain deep gas reserves. Shell, BP, ExxonMobil, Amerada Hess, Kerr-McGee, BHP Billiton, Dominion and Murphy are active Gulf of Mexico players.

What is lacking in the Gulf of Mexico scene is news of significant major discoveries. There are occasional bulletins of successful wells, including those in ultra-deep waters – such as that recently by Unocal and partners in Walker Ridge – but no announcements of finds of large fields over the past few years. Whether the coming year will bring surprises is impossible to say.

	2000	2001	2002	2003*
Production				
Texas+	5,282	5,360	5,252	5,325
Louisiana	1,455	1,503	1,538	1,600
Other states	13,461	13,767	13,179	13,275
Total Production	**20,198**	**20,630**	**19,969**	**20,200**
Imports				
Canada	3,544	3,729	3,777	3,750
Mexico	12	10	2	1
LNG	226	238	229	300
Total imports	**3,782**	**3,977**	**4,008**	**4,051**
Supply from storage and supplemental gas	913	–1,079	527	180
Losses, etc++	–2,130	–1,999	–3,774	–3,620
Total supply	**22,763**	**21,529**	**20,730**	**20,811**
Exports	244	373	516	600
Total consumption	**22,519**	**21,156**	**20,214**	**20,211**

* forecast
\+ includes federal offshore
++ extraction losses and unaccounted-for gas

Source: Oil & Gas Journal, *US Energy Information Agency*

Table 2: US natural gas supply and demand, 2000–2003 (bn cf)

Moving security up the oil and gas agenda

As the global oil and gas industry becomes increasingly integrated the potential for security breaches rises. How serious is this and what should the industry be doing? In the second* of this occasional series, *Tim Aikens*, Managing Consultant at Syntegra, raises the issue of security.

The ability to communicate and transfer data all over the world in real-time has become so embedded in international operations that ICT (information and communications technology) is essential for continued business survival. The oil and gas industry is increasingly using this ability to transform itself on a global scale. But it is a double-edged sword. For while ICT has revolutionised business, it also provides growing opportunities for security breaches – deliberate or accidental – as well as increasing the consequences of such a breach.

The question of security is, therefore, one of the most serious issues facing the oil and gas industry today – and one that needs to be addressed not only as an infrastructure or software problem, but at the highest commercial and organisational levels. The industry is naturally seeking to make the most of the technology opportunities presented; but it also needs to consider the risks, the commercial impact and how to embrace the very real changes that will need to take place in order to effectively manage security.

Opportunities and threats of technology

One of the factors contributing to the universal adoption of modern ICT is that it is extremely sophisticated and extremely easy to use. Similarly, the tools required to hack into systems have increased in complexity – from password guessing to back door identification, and stealth diagnostics to packet spoofing – while the knowledge required to use them has decreased. This means that both the probability and impact of a security attack are now much higher than even a couple of years ago.

New technologies, such as broadband, are presenting huge benefits. Organisations are developing a greater ability to both operate and monitor facilities remotely, often over long distances. This provides for more effective use of physical assets, as well as staff, and can enable unmanned operations.

But this also presents huge risks. In this case, the superior data transmission is coupled with the need for protection against viruses, Trojans, and denial-of-service attacks that always-on connectivity facilitates. Wireless technologies and collaborative tools also come with a similar combination of benefits and risks. That risk is not limited to business applications – in 1999 a hacker took control of a Russian gas system by penetrating the company's SCADA (supervisory control and data acquisition) system.

Fortunately, technology provides answers to many of the security issues it

raises. The hydrocarbons industry was one of the earliest adopters of public key infrastructure (PKI) and digital certificates as a means of validating data exchange. New forms of encryption are being constantly developed, and are widely used in extremely sensitive areas of government and in the military. Smart cards also offer numerous possibilities and can control access to physical premises as well as to virtual networks.

Biometrics – such as the use of fingerprints and iris scans, for example – are also in an advanced state of development, and, like smart cards, can have multiple purposes. One of the most exciting new developments is radio frequency identification (RFID) technology. This can ensure that only authorised personnel have access to places and systems, but can also guarantee that the right equipment is in the right place and being used in the right way. This could be invaluable in a refinery, for example, where carrying out just one aspect of a complex process at the wrong time can have serious and damaging consequences.

The key sources of risk

The sheer volume of data that is carried over international corporate networks is, in itself, a significant risk. Intellectual property regarding upstream exploration and reservoir management, gained in a capital-intensive high-risk environment, is extremely valuable. Downstream operations relating to customers, partners and trading systems also offer a potentially rich field. As oil companies are constantly transmitting data from one corner of the globe to another, millions of dollars' worth of business critical information is flowing round the world every second.

However, not only is there now much more information to poach, but there are also more access points from which to poach it. Oil and gas companies do not operate within a closed sphere, either physically or virtually. The rise of mobile working and an increased focus on external relationships at the expense of internal ones has relaxed the formerly rigid hierarchical structures. Companies are no longer the sole occupiers of one building, and teams are now spread over many locations. The change can be illustrated by the way security has been exemplified over time – from secure buildings in the 1980s, to managed networks in the 1990s and by mobile virtual networks in the 21st century.

The continuing e-enablement of companies is designed to ensure that information is available to everyone, regardless of the time or the location. Unfortunately, this applies both to legitimate and illegitimate users.

The oil business has almost always operated in geo-politically difficult areas. This currently manifests itself by locating operations in countries within emerging markets, particularly in the former Soviet Union, for example, or in areas torn by civil war and internal feuding. This makes oil companies vulnerable to both physical attack and network security breaches.

In the US, oil, gas and other energy-related organisations have been identified as top targets for attack. According to security firm Symantec's *Internet Threat Security Report* from October 2003, 51% of attacks were launched from systems in the US. Even more worrying is that the number of attacks per company has risen from 31 per week in the first six months of 2002, to 38 per week in the same period in 2003.

The fact that major world economies and the price of crude are so closely pegged is another reason why oil companies are an attractive target for deliberate and malicious attacks. It is commonly assumed that hackers are socially inadequate teenagers with too much time on their hands. This assumption is as dangerous as it is mistaken. It is far more likely that companies will be attacked by individuals who are both educated and motivated by their cause. They will also have the economic means to act and understand the consequences of their actions. Organised crime – in Russia and the US – has a major stake in buying and selling information and identities sourced from infiltrating corporate networks.

Impacts of commercial change

The changing commercial realities which underpin oil company activity bring with them new forms of potential risk. The changing nature of partnerships within the oil and gas industry is one example.

Technology has enabled a much greater degree of collaborative working. Companies can mitigate some of the risk and expense of exploration activity, for example, by adopting a partnership approach. But partners in deep sea drilling operations in the Gulf of Mexico may also be competitors in searching for new reserves off Angola. Add to the equation the number of service companies who work with competing clients and the problem is magnified. As the oil company's enterprise becomes progressively more extended, there are more opportunities for inappropriate access to corporate data. This, in turn, demands more sophisticated solutions both technically and organisationally.

To complicate matters further, oil companies have entered partnerships with specialist providers of ICT services, not only for infrastructure support and customised applications, but also the security measures that surround them. And, as with other sectors, there is a growing trend to 'offshore' ICT services and support to countries with cheaper labour costs, such as India and China.

Information also needs to be stored, inevitably in large data centres. While these are usually located in low risk, stable areas they, too, are subject to similar problems of security. Most companies recognise the need to store information in duplicate, so that if one centre is lost, valuable records are still available. By that logic, the two data centres should be located in different areas – supported by further, extensive network infrastructures. The alternative is to outsource data storage to a hosted site from specialist providers. But even in a hosted environment, organisations need to guarantee the integrity of their information.

All of this raises the question of accountability, and attitude to risk. If a security breach has a serious impact on all parties involved then who, precisely, is responsible? How far will an oil company go to ensure its data and its premises,

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Building on natural expansion and acquisitions

As part of our series of feature articles analysing some of the smaller and intermediate oil and gas companies from around the world – based on information supplied by *Online-Data – we take a closer look at the activities of *Samson Investment Company*.**

Samson Investment Company is a privately-held independent exploration and production company, founded in 1971. Based on worldwide gas production, it is ranked in the top 20 US independent E&P companies. Samson's headquarters are located in Tulsa, Oklahoma, and its international operations include key oil and gas regions in North America (in 18 states), Russia, Australia and Venezuela. The company currently operates more than 3,000 producing wells and holds interests in more than 10,000 others. A number of Latin American countries are also currently under review for possible future investment.

With an energy asset base of 85% natural gas, the company steadily continues to profit and expand. Over the last four years Samson has invested $650mn in new exploration and development programmes and a further $900mn in oil and gas property acquisitions. It continues to seek new opportunities. (See **Figure 1**.)

Finance

Samson's financial strength derives from several sources. It has a strong base of internal capital with significant cash flow from product sales, and maintains lines of credit with a network of US and European banks.

These resources provide the company with the immediate ability to meet its objectives of deploying capital to acquire producing oil and natural gas properties of all sizes and to expand its development and exploration drilling activities, both domestically and internationally.

US operations

US operations account for 75% of Samson's reserves value and encompass a total of 28 geologic provinces in 18 states. Its domestic producing oil and gas interests are concentrated in:

- The Anadarko Basin in western Oklahoma and the Texas Panhandle
- The Arkoma Basin in eastern Oklahoma and western Arkansas
- The Permian Basin
- The Texas Upper Gulf Coast
- South Louisiana
- Gulf of Mexico
- South Texas
- East Texas
- North Louisiana
- Michigan
- California
- Several other US basins

Canadian developments

Since commencing operations in 1989 Samson Canada has consistently grown oil and gas production through both exploration and acquisitions. The Western Canadian Basin is one of the company's key growth areas.

Samson Canada operates in most areas of western Canada. Currently, the core regions are:

- Central Alberta
- Fort St John region of Northeast British Columbia
- Rainbow Lake

Activities include the production, transportation and processing of crude oil, natural gas and associated liquids. Samson's daily Canadian production exceeds 150mn cfe. The company plans to continue to develop additional core properties by acquiring established production – either on an asset or whole company basis, or exploring and exploiting areas with high reserve potential – creating value by building a land position and infrastructure, and utilising technology to reduce finding, development and production costs.

Russian activities

Samson also has offices in Moscow and Ukhta (Komi Republic). Together with its partner Vitol, the company has been developing the Sotchemyu field since 1996. Located in the Komi Republic some 850 miles north-northeast of Moscow and only 150 miles south of the Arctic Circle, the project has presented Samson with a challenging operating environment as winter temperatures can reach as low as –40° C. With the assistance of its Russian workforce, the company has significantly enhanced production, installed state-of-the-art

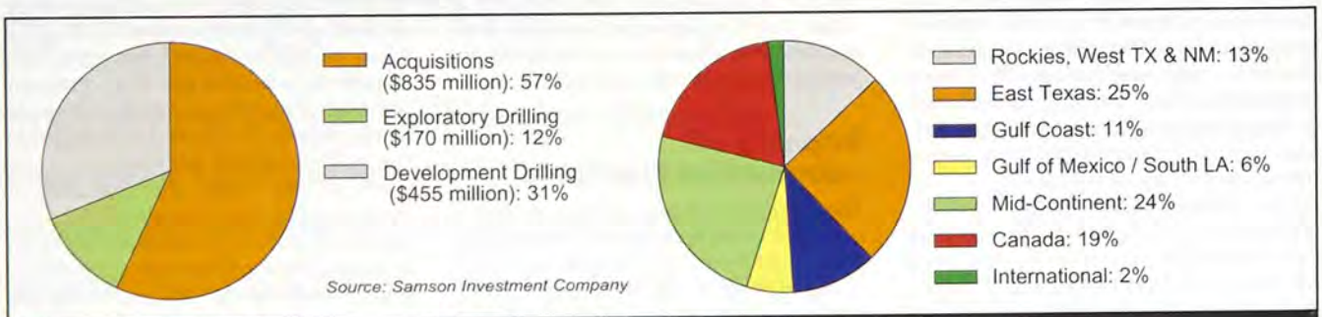

Figure 1: Samson (a) capital commitments, 1999–2002 and (b) reserves by area

communications systems, engaged in development and exploratory drilling, implemented a 3D seismic survey and improved the local infrastructure.

Samson continues to increase production and focus on minimising operating expenses. Over the last calendar year the company has seen a 20% increase in production from 6,000 b/d of oil to just over 7,000 b/d. The company is currently reviewing additional opportunities for investment within Russia.

Venezuelan focus

Samson has been active in Venezuela since 1994, when it was awarded the West Falcon Unit along with several Venezuelan partners. Situated immediately to the east of the prolific Maracaibo Basin, the 890,000-hectare unit is geographically the largest land concession in Venezuela.

Samson's initial task was to reactivate the Tiguaje oil field. The company rebuilt oil-treating and produced-water handling facilities. It also reconstructed a crude oil pipeline and performed a number of workovers and recompletions.

In addition, Samson has discovered natural gas in the abandoned Mamon oil field. Future drilling is planned to exploit this find, which will be marketed as a fuel to nearby refineries. Samson has completed and interpreted a 34-sq. mile 3D seismic shoot for pending exploration activities.

Acquisitions growth

In August 2003 Samson acquired privately held US E&P company Contour Energy. The transaction value, which includes the retirement of Contour's debt, was approximately $146mn. Assets include five fields and six operated platforms in the Gulf of Mexico, as well as operations in North and South Louisiana.

Earlier in the year Samson completed its $29.2mn acquisition of natural gas and oil properties in East Texas and Arkansas from Dominion Exploration & Production. These assets provide numerous drilling locations for further expansion of Samson's activities in the Ark-La-Tex area. ●

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without compromising the need to remain competitive? These are questions that oil companies need to address.

Embrace change and trust suppliers

Security will continue to increase in importance and oil companies will need to give it a correspondingly higher profile. Measures for managing security breaches need to be fast, devolved and able to deal with a more volatile infrastructure, changing threats and the growing availability requirements. They must also be able to address low probability, high impact risks, which are of particular concern in this sector.

Keeping pace with the technology is the easy part – it requires awareness, commitment and investment. What is much harder is making sure that security has a place on the strategic agenda and is ingrained within the organisation. Addressing security is not a one-off activity – it needs constant monitoring and updating. There is growing debate on the specifics of how this can be achieved, and one argument is either for the introduction of the role of Chief Security Officer to the board or to include such a role within that of the Chief Information Officer.

Whether there is a board member to take responsibility or not, a regular security audit is certainly required – whether undertaken internally or by specialist third parties. Given the arena in which oil companies conduct their business, this will require an increasingly open dialogue between partners. Government and defence organisations rely on security partners more and more; so too can oil companies.

As with many other issues, security is about the trade off of risk. It's a question of how much should be spent to reduce security risks to an acceptable level, as well as identifying what that level should be. The relationship with specialist suppliers and the degree of risk that is mutually shared will be crucial.

Over the years, the industry as a whole has successfully developed a real safety culture. The same will now need to be achieved for security. Introduction of technologies such as RFID will bring their own challenges. Oil and gas companies should not underestimate the change in skills, processes, and even culture that may be required to effectively address the security challenges of a truly international business, made effective through global ICT. ●

**See* Petroleum Review, *November 2003*

Glossary of terms

Biometrics
A unique and measurable characteristic of a human being used to identify an individual.

Denial of service attack An attack that is specifically designed to prevent the normal functioning of a system, and thereby to prevent lawful access to that system and its data by its authorised users. Denial of service can be caused by the destruction or modification of data, by bringing down the system, or by overloading the system's servers (flooding) to the extent that service to authorised users is delayed or prevented.

Digital certificates A digital document that attests to the truth that you are who you say you are, and that you own the particular public key specified in the certificate.

Hacker
Someone who uses his or her knowledge to break into another person's computer.

PKI
The software used to manage and control the large-scale use of public key cryptography.

RFID
A form of identification that does not require line-of-sight (unlike infrared or portable data terminals). There are usually three components – antennae (coils), reader transceiver with decoder, and transponder (tag).

SCADA
SCADA (supervisory control and data acquisition) is a technology that enables users to monitor and control their equipment and processes. They are typically deployed with dedicated communication infrastructure, software and hardware to monitor and control large, complex and mission critical installations such as power stations and oil and gas pipelines.

Smart cards
A plastic card normally the same size and shape of a traditional credit card, but includes a microprocessor and a user interface. Information contained on the card or generated by the microprocessor can be used for different purposes. It requires a smart card reader to transfer the data from the card to a computer. It is often used to authenticate its owner.

Trojan
A computer program that has a useful function, but which also contains additional (hidden) functions. The hidden functions may secretly exploit the legitimate authorisations of the invoking process to the detriment of the system's security – for example, by making a copy of a sensitive file for the creator of the Trojan Horse.

Virus
A program which has the ability to copy itself to other computers or disks, without being asked to do so by the computer user.

Mood sours amid prosperity

A wave of what a veteran oilman described as 'economic nationalism' is washing over newly prosperous Kazakhstan, reports *Christopher Pala* from Almaty.

In a pointed snub to the US and the Western oil companies that Kazakhstan depends on to exploit its vast but hard-to-reach reserves, Mercator Corporation – whose Chairman James Giffen is under federal indictment in New York on charges of funnelling $60mn in oil-company kickbacks to President Nursultan Nazarbayev – has been rehired as Consultant to the Authority, Kazmunaigaz. In the 1990s Giffen was the indispensable intermediary between the oil companies and the newly independent government.

Mercator's return was, one well-informed lawyer said, 'rather curious, given earlier statements in the litigation made by Kazakhstan distancing itself from Giffen. It shows that Giffen continues to exert a lot of influence at the top.' Meanwhile, a government spokesman said that the Giffen case was a matter between Americans and had nothing to do with Kazakhstan. He declined to comment on Mercator's rehiring.

More than one-third of the alleged bribes were paid by Mobil Oil Corporation before it merged with Exxon in 1998. ExxonMobil is now under investigation. The company's chief spokesman, Tom Cirigliano, declined to comment on reports in Almaty that the ExxonMobil team at the talks were unhappy about facing David Giffen, James's son and Mercator's representative, at the negotiating table.

James Giffen, indicted in April by federal prosecutors in New York, is restricted to that city's general area as he awaits trial.

Kashagan delay

The talks Mercator has been hired for have been dragging on for nearly a year. They centre over how much of a penalty the North Caspian PSA consortium developing the super-giant Kashagan field must pay for submitting a development plan that provides for first oil in 2006 instead of 2005. The delay is due to the technical difficulties that the field presents. The oil is located some 4 km to 5 km deep in an ecologically sensitive part of the Caspian Sea that is 5 metres deep on average and freezes in winter. It is under very high pressure and contains high levels of hydrogen sulphide.

The consortium – which includes ExxonMobil, Agip, Shell and Total, with 20.37% each, and ConocoPhillips and Inpex sharing the rest – say they have made the 'reasonable efforts' mentioned in the PSA 70 times. Nazarbayev says they have violated the contract and must pay a penalty. As a result of the consortium's refusal to pay the hundreds of millions of dollars reportedly sought by the government and to start developing the field without the government's signature, the project has been delayed by another year, and at year's end there was little sign of progress.

Thus, sources close to the consortium suggest that the 2004 April-to-November construction season may go the way of the 2003 season. 'They have a pattern of going for money today over money tomorrow,' said Caspian analyst Laurent Ruseckas, Director for Emerging Europe & Eurasia at the Eurasia Group. Furthermore, he noted, the Kashagan PSA is heavily front-loaded, with royalties only beginning to kick in five years after the first oil is sold. 'By 2011 or so, the Tengiz and Karachaganak fields will be bringing plenty of revenue,' he commented. This argument was highlighted by the announcement by Agip KCO that the third and fourth wells drilled in the Kashagan area had struck oil.

Fewer foreign incentives

Meanwhile, the contractors hired by Agip KCO, the operator, saw their VAT tax exemption effectively removed in 2003. Consortium sources say solving that problem will have to wait for the issue of the penalty – technically an increase in the production bonus – to be resolved.

The government is also preparing to offer less and less attractive conditions to foreign partners for the exploitation of offshore blocks due to be offered in 2004, arguing that it can afford to do so now that economic stability has been achieved (see box). These new contracts will lose the tax stability clause and will be subjected to a new crude export tax that was due to come into effect at the start of 2004. The tax will be set by international crude prices and will kick in if they rise above $19/b, to a maximum of 33% at $40/b.

Under the rules the foreign partners in these new ventures will not be allowed to own more than 50% of the fields, while

President Nursultan Nazarbayev

footing the entire bill for exploration. The other 50% will be controlled by Kazmunaigas, the state oil company and industry regulator whose Deputy Chairman is Timur Kulibayev, one of the President's sons-in-law. He is reputed to be the country's second most powerful man, with interests ranging from banking to caviar. Martin Firstl, Shell's Kazakhstan Country Representative, was quoted as calling this a 'bitter pill to swallow' that would 'scare off' foreign investors.

Fast growing economy

The rising hostility to foreign investors comes at a time when Kazakhstan's economy has been enjoying the fastest growth rate in the world after Equatorial Guinea. But unlike Guinea, the oil sector only accounts for 20% of the economy, with the banking sector doubling every two years. IMF experts say the economy's biggest challenge is how to carry out reforms that will allow the rising inflow of cash to be put to the best use.

The picture is also rosy in other sectors of the oil industry. The $3.5bn expansion of the Tengiz field, the country's second largest, is proceeding apace. Production in three years is due to rise from 275,000 b/d to 460,000 b/d. However, in a conflict similar to the one ongoing in Kashagan, Tengizchevroil's Western partners – ChevronTexaco with an interest of 50% and ExxonMobil with 25% – had stopped the project for three months, at a cost of some $200mn, because the government had wanted them to provide interest-free loans to cover the share of Kazmunaigas, which has 20%. Lukoil holds the remaining 5%. In the end, the two US

companies guaranteed loans to KMG. However, KMG is paying the interest, sources close to Tengizchevroil have said.

Kazakhstan-China pipeline

Another piece of good news has recently come from Beijing. Once thought to be a distant fourth in the list of possible outgoing pipeline routes – after Russia, Turkey and Iran – China announced late in 2003 that it would pay for an $800mn, 1,000-km pipeline running from central Kazakhstan to the Chinese border.

The move fits in with China's rising appetite for Caspian oil. During 2003 Chinese companies tried to buy a 16% stake in Kashagan, but all the other partners except Inpex preempted. In September, CNPC agreed to buy ChevronTexaco's 65% in the North Buzachi field and plans to increase production from 8,000 b/d to 40,000 b/d. It already owns the other 35% of the project. CNPC also owns a controlling interest in Oktobemunaigas, which produces about 100,000 b/d. The oil from both fields is expected to start filling the pipeline to China.

New tax rules to boost Kazakh coffers

Kazakhstan has adopted new tax rules to reap more money for state coffers when oil prices are high and to develop the oil refining sector. The bill, proposed by President Nursultan Nazarbayev and backed by the Lower House in late November, was given speedy approval by the Senate upper chamber. The law is expected to come into effect on 1 January 2004.

Previously, terms in deals with foreign oil investors were fixed by contract. The new rules force producers either to work under legislation, which could change, or enter production sharing agreements (PSAs), which will from now on guarantee the state a minimum share.

A new oil export tax has also been developed, which would rise proportionately to the price of oil.

The Kazakh Parliament has also given its final backing to several government amendments to PSA legislation. Senators agreed that new petrochemical facilities built by investors working under PSAs should be relieved from corporate income tax if they are built within four years of a contract being awarded and cost more than $30mn. This is expected to help bring in new technologies and develop oil processing. The state's share in the total volume of production from an oil field in the period between initial investment and the moment it starts yielding profit has also been cut from 30% to 20%. In line with the bill, the government also set a minimal profitability margin of 15% for new oil contracts.

In a bid to dispel the fears of those foreign investors already operating in Kazakhstan, the government has repeatedly stated that the new rules will apply only to new contracts.

The digital oil field – a focus on the future

Development of the digital oil field is gaining momentum. The barrier is no longer technology but the need for significant change management. Those E&P companies willing to take the initiative could realise significant economic benefits, according to the latest research and key service suppliers, reports *Brian Davis*.

The Digital Oil field of the Future (DOFF), or Smart Field, will use advanced technology and business optimisation models to monitor and manage operational activities in real-time for downhole and surface facilities. New tools and techniques will boost data provision, improve decision making, enhance production planning and operations, and deliver better hydrocarbon recovery from new, and some established, oil and gas fields.

A multi-client study by Cambridge Energy Research Associates[1] (CERA) promises a mouth-watering list of benefits. CERA estimates an additional 125bn barrels of reserves could be recovered. Operational costs could be cut by between $4bn and $8bn a year. Improved well management, debottlenecking and process optimisation could boost production rates between 2–6%. The move to more remotely monitored and controlled facilities will reduce operating and capital expenditure as facility costs are forecast to fall 5–10% over the next few years, with larger gains to come as unmanned and 'intelligent' subsea facilities become the norm.

Total asset awareness

The key to delivering the digital oil field is 'total asset awareness'. Operators and service contractors will gain continuous, wide-ranging data in real-time using robust supervisory control and data acquisition (SCADA) systems and sensors to characterise downhole conditions of pressure, temperature and 4D (time-lapse) seismics. The introduction of intelligent completions, real-time drilling (RTD), remote actuation and other tools, will boost operational efficiency – for example, RTD could reduce drilling costs by 5–15%.

The prime key to success will be increased integration of powerful analytical tools, for performance optimisation along the E&P supply chain. 3D visualisation and modelling tools will facilitate better multi-function team analysis. But there are still barriers to overcome in terms of the integration of databases, analytical tools and performance models.

Multi-site work sessions that link global operations in real-time are already underway by oil majors such as BP and Shell (see *Petroleum Review*, December 2003).

CERA stresses the need to maintain a holistic view of the digital oil field. Maximum benefits come from strong interaction between activities monitored and controlled downhole, at surface facilities, and along the supply chain.

Data standards being developed

Industry bodies such as the Petrotechnical Open Standards Consortium (POSC) along with key service players such as Halliburton, Schlumberger and WellDynamics, are encouraging the development of data standards for better integrated analysis and well management. POSC played a vital role in development of the data format standard WITSML (wellsite information transfer standard mark-up language), which facilitates easy data transfer for real-time drilling operations.

No single vendor can provide an all-encompassing solution, so it's a matter of mix and match. Most leading system providers favour more 'open' systems, and offer integration toolkits to help glue databases and analytical applications together.

Major oil companies and service providers talk of the need for 'closed loop' systems that will 'monitor, model, optimise and control' operations automatically. Today, most digital oil field pilot projects are 'open loop systems' with a significant degree of human intervention. The most common method of integrating systems into a network for optimisation modelling involves using a dedicated messaging platform, rather like sending an email from one machine to another.

Industry experts agree that the biggest barrier to the digital oil field is the need for strong change management. CERA estimates that DOFF will enable firms to operate some fields with 50–80% fewer workers, particularly in deepwater oil fields; whereas the benefit for more mature gas fields is not so compelling. However, the introduction of more centralised monitoring and diagnosis and control from, say, Houston or Aberdeen, could boost net present value (NPV) of new deepwater oil field developments by 5–40%, depending on the field parameters.

There will be a need for buy-in by management, service and operational personnel. This calls for major re-skilling and development of cross-functional teams. The need for new skills and services will allow service companies to differentiate themselves, and also offers opportunities for newcomers. CERA also suggests that the introduction of DOFF calls for the reshaping of fundamental relationships between host governments, national oil companies and the service industry.

Leading service companies and the development of oil majors are already committed to developing an integrated, broad-scale approach to the digital oil field.

Halliburton – playing out more scenarios

'Oil companies need to create a high level view of the digital oil field initially,' comments Alvaro Escorcia, Director of Real-Time Reservoir Solutions, Halliburton Energy Services Group. The optimised operating plan should consist of a broad description of major E&P workflows upstream with models and projections stored on computer systems. The performance of the field operations is measured against

the plan using real-time technology (eg sensors, 4D seismic) to judge key performance indicators (KPIs) in terms of people, production and financials versus the plan. The operating plan is then modified in real-time with modelling, analysis and measurement.

Halliburton is concentrating its real-time reservoir solutions strategy around understanding four macro workflows: prospect generation, field development, drilling and completions, and production operations. Each of the four major workflows has a slow and fast loop (see **Figure 1**). In the exploration area, a slow loop could be two to three years, and a fast loop – a week. In the production area, a slow loop could be a few days or months, but a fast loop could be seconds for valve actuation.

The digital oil field asset development plan will contain numerous scenarios. Key performance elements (physical and financial) must be measured continuously and compared against plan. As the development progresses, results are evaluated, 'what if' scenarios are played against the forecast, and changes made. All these steps should be carried out concurrently, so the operator can fine-tune the operational mix in real-time.

Landmark's real-time technology and applications are focused on decreasing the cycle time between key decision points throughout the four macro workflows. For example, a client recently identified a lease sale opportunity on a Friday before the Monday deadline. The seismic data was accessed within PetroBank as part of an optimised workflow for prospect generation, interpreted, and the proposals submitted over the weekend. Several end-leases were secured. This process would normally have taken weeks without online access to vendor data in PetroBank.

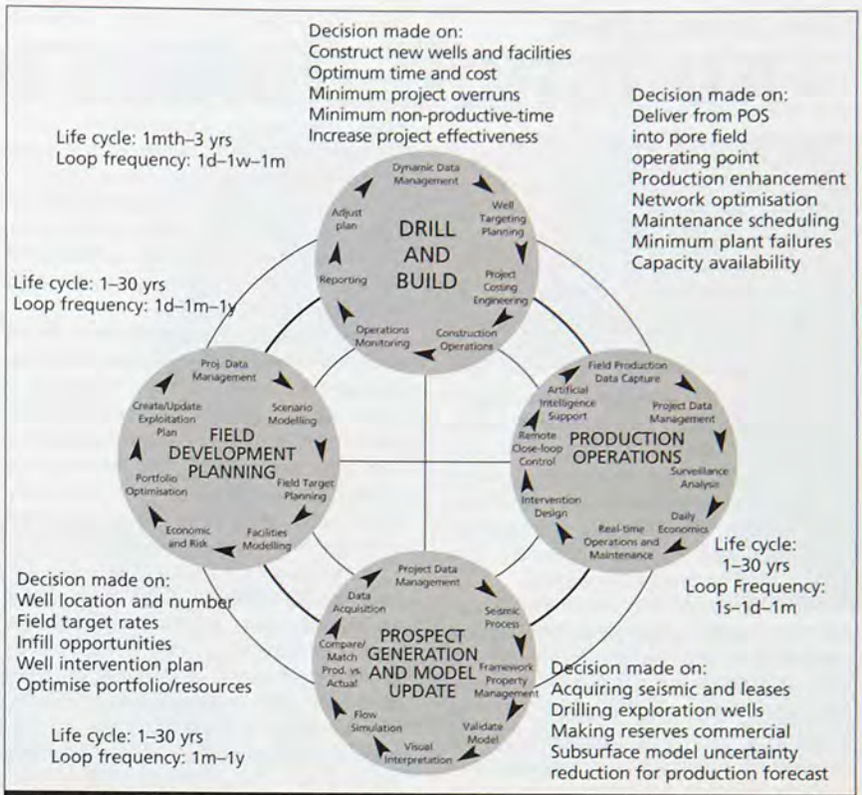

Figure 1: Workflow processes in the oil field, long-term

Integrated visualisation enables the asset team to use real-time field data as an integral part of reservoir development plans. Landmark has developed a suite of tools called Decision Space, in which one of the modules, AssetView, allows drilling and completions operations data to be viewed within the context of the earth model. For example, daily drilling reports are shown alongside real-time well measurement and log data (MWD/LWD) and subsurface structural and reservoir models.

'The Decision Management System module allows the asset team to run numerous field scenarios automatically, with changing emphasis on various reservoir model properties. This helps teams better understand the risk associated with a range of scenarios,' says Helen O'Connor, Director of Real Time Systems at Landmark Graphics.

PROCESSES	**Measure & Monitor** Downhole, seabed and surface conditions monitoring	**Modelling & Interpretation** Reservoir, well, surface network and equipment modelling	**Optimise** Exploitation plan, field targets, network resource allocation	**Integrate** Short and long-term surface and sub-surface	**Control & Actuate** Downhole, seabed and surface actuators
TECHNOLOGY	Downhole Sensors Distributed Fiber Optics Seabed/Surface Sensor Production Surveillance Field Surveillance Abnormal Situation Management	Geological Model Fluids Model Reservoir Simulation Wellbore Model Surface Network Model Process Model Economic Model	History Match Nodal Analysis Network Optimisation Injection Conformance Portfolio Optimisation Uncertainty & Risk Export Optimisation	Short- vs. Long-Term Surface and Subsurface Production & Completion Reservoir and Production Operations and Maintenance Real-time and Static Data	Advanced Automation Downhole Actuators Seabed Actuators Surface Actuators Flow Choke Devices Process Control

Figure 2: Smart Fields technology framework

Silos of disciplines

Luigi Saputelli, Global Advisor for Real Time Production Optimisation, takes up the story. 'In the past oil companies were organised in 'silos of disciplines', with geologists focused on reservoir descriptions, production engineers who designed facilities, drilling engineers for drill architecture, and so on.'

The smart approach allows a multi-discipline asset team to interact concurrently, with significant cost and time saving, using an integrated asset management approach. For example, BP's Field of the Future initiative features independent asset management teams with a 360° view of geology and production, and access to feedback from every knowledge community in a vertical domain. Traditionally, the production engineer lacked access to the sub-surface or predictive model.

The new tools for Smart Fields can handle a wide range of tuning nodes/parameters, eg for choke point, gas lift injection point, separator pressure, injection rate, and steam's equilibrium. The tuning parameters can be calculated automatically and continuously to provide an optimum point for economic operation. Various components of Halliburton's Real Time Reservoir Management Services framework have been deployed. These are currently used mostly in open loops, with a degree of human intervention, rather than in fully automated closed loop systems.

Smart Field in practice

In the southern North Sea, a major gas operator manages an open loop system which receives downhole and surface facility measurements from 27 plots via a networked SCADA system, integrated with a real-time asset management strategy. The company has a complete view of the supply chain, with KPIs that provide maximum value from the asset, eg a choke model to identify production constraints. As a result, the operator has reduced Opex costs 10% in less than one year of operation.

Conventional process control systems on platforms provide thousands of signals, so it is almost impossible to distinguish between normal and abnormal events. The smart advisory system is integrated with the sub-surface, and tells the operator when he is on track or has room for improvement. As Smart Fields develop, further tools can be integrated for workflow optimisation, knowledge management, procurement, transportation and risk reduction.

Halliburton has developed the concept of the 'Oilfield of the Future' for several years. Its vision extends beyond software and well services operations. Sister company KBR (formerly Kellogg Brown & Root) provides real-time production optimisation while WellDynamics, a joint venture with Shell, has developed SmartWells™ technologies. These systems provide operators with the ability to monitor and control operation of surface and subsurface production systems with real-time optimisation.

'Developing the digital oil field means companies must become more information-centric,' says Escorcia. Adopting a smart approach requires careful assessment of company needs, opportunities and priorities. Halliburton recommends using a tool like Value Finder™ to identify key areas of action that can be improved with real-time digital techniques.

'Focus on simplicity,' says Escorcia. 'It's like peeling an onion. Companies need to identify pain points to get buy-in and enterprise commitment. For drilling operations, companies can find relatively easy opportunities for quick hits, because it is easy to map performance indicators and see the value generated. Others focus on propagating best practice to streamline global operations. The oil majors appreciate the opportunities for incremental implementation of production optimisation technologies. However, there are big gains to be had from thinking ahead, starting with optimised field development planning and leveraging the value of the information throughout the life of the field.'

Real-Time Technology interest group

The Society of Petroleum Engineers (SPE) has a 200-strong technology interest group (TIG) to address the issue of real-time optimisation (RTO). The SPE stresses the need for a focused business case, based on financial performance of the existing production infrastructure or the performance over the life of the field. The latter is more complex, because of the need to predict a geological model that will be accurate for the remaining field life, and the need to guess the oil and gas price over that period.

According to an excellent paper[2] given by the SPE at Offshore Europe 2003: 'In designing an RTO system and evaluating its value, it is important to examine the lifecycle value as well as the short-term gain.' Here again, the SPE emphasises the importance of getting buy-in from operators, managers and engineers for proper implementation. Some reckon that getting buy-in may be a generational issue.

Schlumberger – compelling reasons for going Smart

'The business case for real-time initiatives are proving to be compelling, solid and repeatable,' comments Hovey Cox, Schlumberger Information Solutions Real-Time Development Project Manager.

Schlumberger has seen clients' field production rates improve 3–10%, drilling time cut by 25%, and drilling hit ratios rise from a field average of 35% to 65%. Schlumberger has also seen drilling failure rates reduced dramatically, based on collaborative and integrated planning, real-time drilling and virtualised access to expertise. As this trend continues, more centralised control will be used to run, monitor, diagnose and guide multiple wells and fields worldwide. Reduced manning in remote locations will also significantly influence both cost and safety.

'Generally, the cash-flow curve over the life of a field will shift to the left, beginning with the generation of prospects through the field development process, to enhanced production,' says Cox. Improved secure access to information worldwide will allow a group of experts, or ultimately autonomous loops, to make decisions and impact on events in the field at the critical time – whether a pump is overheating, water is breaking through or a drill bit is entering the reservoir sand. Cox maintains: 'Real-time access to information will allow companies to react to market changes far faster.'

Where should companies start for real-time initiatives and development?

Cox recommends looking at core operational processes, such as drilling or production. 'Look at an entire loop (ie one part of the operational process) from the reservoir to the worldwide desktop and back. Focus on the loop foundations – technology, information flow, security, connectivity, software applications and expertise. Then you analyse each opportunity from a cost, risk and potential benefit standpoint. Make sure there is a clear business case. Then you can design, develop and implement, with the right level of change management, the new optimised or transformed real-time process.'

Considering their positive impact on the business, Cox is convinced that real-time initiatives are one of the most intriguing and active areas in oil and gas today.

1. **www.CERA.com**
2. 'Promoting real-time optimisation of hydrocarbon producing systems', SPE, September 2003.

BP set to match donation

Following the outstanding individual achievement ovation received by Vicky Robinson for her project 'Beyond Petroleum and Blessed Pupils', 2003 Awards guests gave willingly towards a collection for the Hekima Orphans Foundation in Tanzania. The collection raised £1,159.34 which BP has generously agreed to match.

Above: Louise Kingham, Chief Executive, EI, presented John Mumford OBE, Director, BP Oil (UK) and EI Council Member with a cheque for the amount at the EI's EGM in December. She said 'the EI is delighted that the IP Awards not only recognised Vicky's achievements but also provided the opportunity to enable others to contribute'. John Mumford, thanked the EI and all those who made a donation at the Awards.

Left: Vicky Robinson with children at the Hekima Orphans Foundation in Tanzania

Electric Storm lights up London

Shell unveiled Electric Storm on London's South Bank on 19 November 2003. The ethereal show of mist, light and music among the trees lining the Thames is a display evocative of the northern lights.

Did you know...?

- The UK is the windiest country in Europe and the resource is much greater during the colder months of the year, when energy demand is at its highest (www.yes2wind.com).
- Wind turbines in the UK produce enough electricity each year to boil 8,200,674 kettles or over 2ms gallons of water (www.bwea.com).
- In order for a wind turbine to work efficiently, wind speeds usually must be above 12 to 14 miles per hour (www.energyquest.ca.gov/story/chapter16.html).
- There are currently 82 wind energy projects in the UK, with a total of 1,030 turbines. These are largely situated in Wales, Northern Ireland, Cornwall and the North of England. Together they produce an installed capacity of 587.6 MW of power, which is enough to power 386,000 homes (www.bwea.com).
- The UK's 82 wind projects reduce carbon dioxide emissions by 1,330,000 tonnes, sulphur dioxide emissions by 15,400 tonnes and emissions of nitrogen dioxides by 4,630 tonnes. (www.bwea.com).
- One 600-kW wind turbine at a 'reasonable' site would produce enough electricity to meet the annual needs of 375 households (www.bwea.com).
- Renewable energy sources in the UK currently generate almost 3% of total electricity supply, 14% of which comes from wind energy (www.bwea.com).
- Blyth offshore wind farm, the first offshore wind farm to be built in UK waters, comprises two of the world's most powerful wind turbines – each of 2 MW capacity (enough to power 3,000 households). They are the largest to be erected offshore in the world. Shell Wind Energy jointly owns Blyth with partners NUON, Powergen and AMEC Wind. For further information visit www.dti.gov.uk/energy/renewables
- Denmark already gets 20% of its electricity from wind power (www.yes2wind.com).
- In 1888, Charles F Brush, who is one of the founders of the American electrical industry, built what is today believed to be the first automatically operating wind turbine for electricity generation. The turbine had a rotor diameter of 17 metres and 144 rotor blades (www.shell.com).
- Turbine technology is constantly changing. In 1988 generator capacity of an average wind turbine was around 100 kW, nowadays turbines of 4.5 MW are being tested for commercial applications (www.shell.com).

The show's installations – powered entirely by renewable energy from a 43-metre wind turbine located near Hungerford Bridge – stretch half a kilometre along the South Bank from the London Eye to the National Theatre. There will be a different display every evening until mid-February, as Shell Electric Storm reacts in harmony with prevailing weather conditions – from high winds through to total calm.

Shell Electric Storm aims to engage the public on the issue of renewable energy in an entertaining and compelling way. Rather than presenting it as a problem facing today's generation, Shell Electric Storm aims to capture the imagination and bring wind energy to life by providing a physical experience of the power it can produce. At the same time the show will create a vibrant atmosphere along London's South Bank during winter and will make a virtue of the long nights and windy weather.

The concept is the brainchild of Make Communications, assisted by Arup. Shell is the lead sponsor of the project, working with the DTI, Fortis Bank, EDF and Norton Rose, with the support of the South Bank Centre and South Bank Marketing Group.

Wind power at work

The energy from the 225-kW wind turbine does not feed directly into the tree installations, but is routed into the Royal Festival Hall and fed into the National Grid, from where the energy needed to power the light, mist and sound show is drawn. This replicates the process that takes place on a wind farm – the energy generated by the turbines is fed directly into National Grid, from where it is taken to meet energy requirements across the UK.

The mature trees along the South Bank house separate light, mist and sound units. There are single units in each tree and the system is designed so that if one unit fails, it will have minimal effect on the overall installation. Three distinct types of lighting effect form the central core of the installation – 'ambient', 'gesture' and 'hotspot'. For the purposes of the recyclable, low-energy lighting units, the trees are divided into 10 groups. Each tree within the group has 10 different controls, enabling sequential switching and giving the whole installation the possibility of creating a multitude of differing effects.

High-pressure misters, similar to those used in greenhouses and for agricultural purposes, produce a wind-borne micro-mist of water through a number of nozzles in each tree.

The sounds of the show come from a number of speakers positioned at different points along the South Bank – in some instances located on trees, others attached to the nearby buildings. The speakers are strategically positioned to allow the sound to move around those experiencing the display.

As with all the elements of the show, the Timax sound system is controlled by the prevailing weather conditions. Anemometers and mini weather stations at various points along the South Bank collate meteorological data, which then programme all the show elements to make an ever-changing 'real time' experience.

Spreading the word

Text relating to the issues around Shell Electric Storm – renewable energy and sustainable resources – will be incorporated into the existing benches along the South Bank throughout the duration of the show. It provides additional information and interest for visitors and directs people to the Shell Electric Storm website where they can find more information on renewable energy **www.shellelectricstorm.com**

In Brief

...continued from p6

Chevron Oversea Petroleum Azerbaijan *(COPAL) is reported to have ended its exploration and development project over the Apsheron structure in the Azeri sector of the Caspian Sea, having found no commercial reserves.*

Total and ExxonMobil have announced *the discovery of hydrocarbons following exploration drilling on the Aktote and Kashagan South-West prospects in the North Caspian region in Kazakhstan. Aktote flowed 1,550 b/d; Kashagan South-West 2,200 b/d.*

ExxonMobil and Socar are reported to *have withdrawn from the Ogu project in Azerbaijan having found no commercial volumes of reserves.*

ChevronTexaco is understood to be *planning to invest about $4bn in the Kazakh oil and gas sector over the next four to five years. The company has already invested over $4bn and has approved expansion projects for Tengizchevroil, the Caspian Pipeline Consortium (CPC) and Karachaganak.*

CNPC of China is reportedly consid- *ering acquiring the White Nights oil company from the International Industrial Bank for $150mn.*

Lukoil-Perm, the operator of Lukoil *Overseas's Russian assets, has begun pumping oil through the Yuzhno-Rayevskaya pump station at the Magovskoye field in the Krasnovishersky District of the Northern Perm Region. Four wells are currently producing some 22,600 t/y of oil from the field. Proven reserves will allow for an increase in output over the next seven years to 497,000 t/y. Magovskoye also holds 1.98bn cm of gas reserves.*

The BP- and Statoil-led consortium *developing the Shakh Deniz field, with reserves of 625bn cm of gas and 101mn tonnes of gas condensate, is to spend $3.2bn to build an offshore platform and a pipeline to supply Turkey with up to 6.5bn cm/y gas from 2007–2009, reports* Stella Zenkovich. *Each holds a 25.5% stake in the project. The remaining partners are Total and LukAgip, a joint venture of Lukoil and Agip.*

Asia-Pacific

CNPC is reported to have discovered *79.43mn tonnes of oil reserves in China's northern Tarim Basin. The find is also thought to hold 100bn cm of gas reserves.*

China is reportedly planning to build *a $1.2bn national oil reserve, capable of storing 5mn tonnes of oil – equivalent to 10 day's supply – by 2005. The reserves will be located in Qingdao in Shangdong Province, Huizhou in Guangdong Province, and Ningbo and Zhoushan in Zheijiang Province.*

Gradav, the sole bidder for *ExxonMobil's oil and gas assets in the central Australian Cooper-Eromanga Basin is reported to have said that a delay in finalising the acquisition was due to the deal's complexity and not related to financing. The stake has been valued by analysts at between A$600mn and A$800mn.*

Oil and Natural Gas Corporation *(ONGC) is reported to have won five of the nine coal bed methane (CBM) blocks on offer in India's latest licensing round, Reliance Industries secured three blocks. The government received 14 bids for eight of the nine blocks on offer – the Godavari block GV (North)-CBM-2003/11 eliciting no interest.*

The Cuu Long Joint Operating *Company, an international oil exploration consortium including the Korea National Oil Corporation (KNOC) and SK Corporation, is reported to have discovered oil in the Su Tu Trang, or White Lion, area, offshore Vietnam. The new field is thought to be larger than the Su Tu Den (Black Lion) field, which is currently producing 60,000 b/d.*

CNOOC is understood to be planning *to drill an exploration well, Nanping 11-4-1, in the East China Sea before the close of 2003 as part of plans to increasingly focus exploration attention in this region.*

Latin America

A Petrobras-led consortium is under- *stood to have been awarded a second block to develop gas reserves in Mexico after a bid by a Chinese consortium was rejected on technical grounds. The group formed by Petrobras, Japan's Teikoku Oil Company and Mexico's D&S Petroleum bid $265mn for the Fronterizo block, the sixth of seven being tendered by state oil company Pemex to produce gas in the Burgos Basin. The contract is for for 15 years and the consortium is expected to drill 100 wells and raise production to 34mn cf/d. The consortium has also secured the Cuervito block, with an earlier bid of $260mn.*

Africa

Total (40%, operator) and partners *have brought onstream the Jasmim oil field in block 17 offshore Angola, increasing oil flow to the Girassol FPSO to more than 230,000 b/d.*

training courses 2004

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OIL AND GAS INDUSTRY FUNDAMENTALS

COURSE DATES:
11 - 13 February, 2004
COURSE VENUE:
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£1400.00
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This **three-day course** comprehensively covers the oil and gas supply chains from exploration through field development, valuation and risk, production, transportation, processing and refining, marketing, contracts, trading, retailing, logistics, emerging markets and competition with alternative energies. As such, it provides understanding and insight to the processes, drivers, threats and opportunities associated with the core, industry activities.

WHO SHOULD ATTEND?

Personnel from a range of technical, non-technical and commercial backgrounds, new industry entrants and those with expertise in one area wishing to gain a broader perspective of all industry sectors. It also provides a valuable, industry overview for those requiring an informed introduction to the economic and commercial background and general trends within the oil and gas industry.

PRICE RISK MANAGEMENT IN TRADED GAS AND ELECTRICITY MARKETS

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On this **five-day course**, delegates will identify the areas of price risk in different areas of operation; trade futures, forward, swaps and options markets; hedge and then manage a corporate position; analyse price charts; separate price and supply through the use of exchange and OTC instruments

WHO SHOULD ATTEND?

Those affected by changes in the international gas and electricity prices, including those in: companies affected by traded markets in the gas and electricity industries; the supply, marketing, finance and planning departments of gas, electricity and integrated energy companies; energy related government departments and regulatory authority staff; purchasing, planning and finance in major energy consumers; energy publications; banks, accountants, auditors and others associated with gas and electricity companies; advisors and policy makers.

INVESTMENT PROFITABILITY STUDIES IN THE PETROLEUM INDUSTRY

COURSE DATES:
24 - 27 February, 2004
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London, UK
EI MEMBER:
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(£2232.50 inc VAT)
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£2100.00
(£2467.50 inc VAT)

This **four-day course** takes participants from the fundamentals of investment profitability analysis theory to advanced case studies involving project finance and tax systems of production sharing contracts.

The aspects described include creating value, financial ratios, corporate finance, project finance, cost of capital, discounting, economic criteria and economic decision, financial leverage, impact of taxation and inflation, discounted average cost, return on equity, leasing and risk analysis.

WHO SHOULD ATTEND?

The course is suitable for managers and staff concerned with decisions affecting medium and long-term cash flows, investment, disinvestment, acquisitions or leasing, who need to improve their understanding of the theory and practice of investment analysis.

AVIATION JET FUEL

COURSE DATES:
17 - 19 March, 2004
COURSE VENUE:
London, UK
EI MEMBER:
£1400.00
(£1645.00 inc VAT)
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£1600.00
(£1880.00 inc VAT)

This **three-day course** is designed to provide a technical overview and to introduce delegates to the many facets of the Aviation Jet Fuel business – a business which operates at a truly global level. It will not only examine the workings of the modern jet engine, but will build the picture as to why, unlike some fuels, jet fuel specification, production and handling is critical to the continuing success of the aviation industry. It explores components of the business from several key perspectives, including oil company fuel suppliers and civilian and military users.

WHO SHOULD ATTEND?

Personnel seeking an overview of the sector; those new to the industry, including graduate trainees, requiring an introduction to the aviation business; managers and professional staff from government departments and agencies; auditors and others associated with commercial aspects of the sector.

2004 COURSES' CALENDAR OUT NOW

For more information, see enclosed inserts or contact Nick Wilkinson
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or visit: www.energyinst.org.uk E-mail: nwilkinson@energyinst.org.uk

training courses 2004

energy INSTITUTE

ECONOMICS OF THE OIL SUPPLY CHAIN

COURSE DATES:
22 - 26 March, 2004

COURSE VENUE:
The Møller Centre, Cambridge, UK

£2150.00
(£2526.26 inc VAT)

On this **five-day course**, delegates will examine the various activities of the fictional Invincible Energy Company to explore the economic forces which drive the oil supply chain. They will concentrate on the main areas of risk and opportunity from the crude oil supply terminal, through transportation, refining and trading to the refined product distribution terminal.

During their time in Invincible's refinery, delegates will learn about the quality aspects of product supply. They will study refinery process economics and the effects of upgrading.

WHO SHOULD ATTEND?

This course is the essential foundation for people entering the oil industry or for those with single-function experience looking to broaden their knowledge. It also forms the basic building block for the other trading related courses.

GAS UTILITIES - FINANCE, REGULATION AND TARIFF DESIGN

COURSE DATES:
22 - 23 March, 2004

COURSE VENUE:
London, UK

EI MEMBER:
£1400.00
(£1645.00 inc VAT)

NON-MEMBER:
£1500.00
(£1762.50 inc VAT)

This **two-day course** draws on the extensive expertise of three people with a wealth of financial and regulatory experience. Not only will they provide views from their perspective in other areas, each will also lead one of the three sections introducing the relevant issues, illustrating them with extensive examples and discussing the implications of the analysis with delegates. Delegates will be given exercises and work in small groups to solve them.

WHO SHOULD ATTEND?

Anyone working in finance or planning functions that have dealings with the natural gas (or more generally, energy) industry; company executives involved in regulatory affairs functions; bankers, commercial, multi-lateral and ECA's; lawyers; those taking up international assignments or seeking international contrasts and comparisons; anyone new to modern gas markets; people in energy companies experiencing opening markets; executives with managerial responsibility, but not operational experience in tariff issues; regulatory staff and new regulators.

CAPACITY TRADING SEMINAR - HOW US AND CANADIAN GAS CAPACITY TRADING WORKS - IS IT APPLICABLE IN EUROPE?

COURSE DATES:
24 - 25 March, 2004

COURSE VENUE:
London, UK

EI MEMBER:
£1900.00
(£2232.50 inc VAT)

NON-MEMBER:
£2000.00
(£2350.00 inc VAT)

This **two-day,** intensive seminar focuses completely on capacity trading. The course will unveil the mysteries of how this works, who benefits, who doesn't, and what goes on in a practical sense in commodity trading of pipeline capacity.

WHO SHOULD ATTEND?

Commercial staff needing to improve their understanding of the commercial issues facing their industries; executives recently charged with running new, European gas transportation companies; the commercial and planning staff at other energy related industries; regulators, their staff, advisors and political masters; bankers, financiers and risk management service providers; legal advisors needing a broad perspective of the gas and electricity industries; consultants, lobbyists and others associated with the energy industries.

LNG - LIQUIFIED NATURAL GAS INDUSTRY

COURSE DATES:
29 - 31 March, 2004

COURSE VENUE:
London, UK

EI MEMBER:
£1400.00
(£1645.00 inc VAT)

NON-MEMBER:
£1600.00
(£1880.00 inc VAT)

This **three-day course** covers technical and commercial perspectives of all segments of the LNG gas supply chain from gas field development, liquefaction processes, shipping, regasification, storage, supply into a gas distribution network, embedded opportunities for LNG within existing gas markets, supply and construction contracts, project finance and economic valuation. This differs from other LNG courses in providing an integrated insight into the technologies, the markets, the economics and the finance of the industry.

WHO SHOULD ATTEND?

Those working in the LNG industry in production, liquefaction, transportation and receiving, including those reliant upon LNG supply or the financing of LNG projects; analysts, planners and commercial staff; personnel operating in the gas, electricity and related energy industries and markets, regulators, advisors and policy makers, bankers, financiers, legal advisors and risk managers.

2004 COURSES' CALENDAR OUT NOW

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Renewables to reduce hydrocarbon use

Indonesia is stepping up efforts to promote its national energy diversification policy to expand the use of renewable energy in a bid to slow down the depletion rate of the country's hydrocarbon resources, reports *David Hayes*. In addition to enhancing the role of renewable energy in ensuring environmental sustainability, the government has introduced regulations to encourage private sector and community participation in renewable energy development through the small power purchase tariff initiative aimed at supporting small power producer schemes.

Rice growing in Indonesia. The potential for electricity generation fuelled by rice husk is 1,600 MW annually

During the past two decades oil, gas and coal resources have become major sources of foreign exchange as well as social and economic development in Indonesia. However, local use of petroleum products has grown rapidly while other energy resources have remained undeveloped, increasing the possibility that Indonesia may soon become a net oil importer to the detriment of government efforts to achieve further economic progress.

Efforts to speed up development of renewable energy will be supported by the government's recent launch of a $256mn programme targeting the development of small and mini hydropower projects and geothermal energy. The Manila-based Asian Development Bank is lending $161mn of the total project costs, which will benefit an estimated 5.2mn people, of whom 1.5mn live below the poverty line.

Key role for PLN

Perusahaan Listrik Negara (PLN), the state-run power utility, will play a key role in implementing the renewable programme, which is expected to involve a large number of small power projects being built and owned by private organisations that will sell their electricity output to PLN. Currently PLN supplies electricity to 49,000, or 84%, of Indonesia's 58,000 villages. Its more than 30mn customer base includes 53%

of the nation's 52mn households.

The project will include the installation of about 76,000 new electricity supply connections. A revolving fund will be established for 10,000 poor households to provide support for initial expenses such as wiring houses, buying fixtures and connection charges.

At the start of 2002 PLN had a total installed generating capacity of 21,003 MW. In addition, independent power plants (IPPs) totalling 3,000 MW were in operation, while captive power plants totalling 12,000 MW had been installed by mainly industrial users who cannot depend on PLN for reliable electricity supplies.

PLN's installed capacity includes diesel-fired stations totalling 2,550 MW and oil-burning plants amounting to 2,827 MW. The utility's gas-fired stations total 7,300 MW. Hydropower plants are 3,100 MW, while coal-burning stations totalling 4,790MW have been installed. In 2001 PLN generated 101,600 GWh of electricity, of which 33.5% was generated by coal-burning stations, 29% by gas-fired plants, 22% by oil-fired units and 12% by hydroelectric schemes, while geothermal stations supplied just 3.4%.

The renewables development acceleration programme will involve constructing power schemes that total 84 MW – mainly geothermal and hydropower schemes, which will generate 480 GWh of electricity a year. Although most individual renewable energy schemes are small, the government believes these can enhance rural economic development as well as supply electricity to replace hydrocarbon use.

Getting the ball rolling

The launch of the programme is expected to spur development of other renewable schemes, which is the main intention of this initiative. Indonesia's Ministry of Energy and Mineral Resources is encouraging the development of micro hydro power plants in villages and solar power plants in urban areas. Wind energy, biomass and geothermal power also are targeted for development.

Earlier this year the Ministry announced the introduction of a power plant designed to burn a mixture of rice husk and diesel. The 100 kW model is a cheaper alternative to diesel-fired generation and is intended to help tackle the country's electricity shortage problem.

According to government figures Indonesia produces on average about 50mn tonnes of husk, equivalent to 43% of the total rice production, every year. The potential for electricity generation fuelled by rice husk is 1,600 MW annually. Most rice husk and diesel power plants will be built next to rice mills supplying electricity to the local community or selling to the national grid.

Geothermal difficulties

Indonesia's geothermal resources are far larger, but are proving difficult to develop as potential investors and banks are deterred by the current lack of guarantees to ensure the financial viability of the geothermal projects. Developing geothermal energy for power generation requires long-term power purchase price stability and a sufficient base load power purchase requirement to ensure profitability.

During the past two decades Indonesia has developed 787 MW of geothermal power, or just 4% of the country's almost 20,000 MW of geothermal potential.

The early 1990s saw the government award eleven contracts for the development of geothermal power plants, with a total committed capacity of 3,417 MW and original completion dates between 1998 and 2002. However, as a result of the 1997 Asian financial crisis, the government suspended seven geothermal projects. Attempts are underway to revive these geothermal contracts but little progress appears to have been made.

Promising hydro potential

Meanwhile, efforts to develop the country's large hydroelectric potential appear more promising. Indonesia, with a total hydropower potential of 75,000 MW, has one of the largest hydroelectric reserves in Asia. Much of this potential is spread across 1,315 possible locations where different sizes and types of schemes could be built.

Although about 50% of Indonesia's hydropower potential could be exploited by building large-scale hydroelectric schemes exceeding 100 MW installed capacity, a large amount of the potential capacity could be developed by building smaller schemes, including mini and micro hydro projects. The Indonesian Government is interested in developing such hydro projects to reduce the cost of supplying electricity to remote communities compared with diesel-fired generation. A target of 59.5 MW had been set for commercial micro hydro schemes by the end of 2003, rising to 153.4 MW by 2020.

According to figures published by PLN, Indonesia's micro hydro potential for schemes between 250 kW to 500 kW is about 493 MW. By 2000 only about 4% of this potential had been exploited by various schemes totalling 21 MW. Most micro hydro schemes have been built in Java and Sumatra.

A potential development figure for micro hydro schemes less than 250 kW in size has not been published as many of these are built to supply power to local communities while most schemes over 250 kW usually sell their power output to the grid. However, the potential for micro hydro schemes less than 250 kW in size is thought to be considerable and could easily exceed PLN's estimate for large micro hydro schemes.

Villages requiring less than 100 kW of power supply will be encouraged to build off-grid micro hydro schemes where sufficient water resources exist. In addition, micro hydro schemes of 25 kW or larger will be used to replace small diesel-fired plants.

A model of development

Indonesia's mini and micro hydropower development programme is expected to create interest in other neighbouring countries. As a result, the United Nations Economic and Social Commission for Asia and the Pacific (ESCAP) has chosen Indonesia as the location for a pilot micro hydroelectric power scheme intended to act as a model for micro hydro development throughout the rest of the Asia-Pacific region.

Construction is due to begin shortly on a 100 kW micro hydro scheme in the village of Cinta Mekar, situated about 150 km from Jakarta in West Java. Work is due for completion so that the scheme can enter commercial operation early in 2004.

The ESCAP project is planned to follow the Small Power Purchase Agreement approach where private developers of small power plants offer surplus electricity generation to PLN to purchase. Known as build, operate and own (BOO) projects, these schemes are attractive to PLN as the cost of purchasing micro hydro generated power is much cheaper than the diesel-generated electricity that PLN may otherwise be required to supply.

Selling electricity bulk to PLN is also attractive to the local community investing in building a micro or mini hydropower scheme. Selling bulk means the community is not faced with problems of collecting payment from electricity consumers. Profits from such schemes are expected to be used to pay for the cost of connecting all homes in the village to mains electricity supplies and to invest in village enterprises that will benefit the local community.

The private investor for the Cinta Mekar project is Hidropiranti Inti Baxti Swadaya Micro hydro Systems, a local turbine manufacturer that will supply the micro hydro scheme with its turbine generator. The shareholdings in the project have been divided 50:50 between Hidropiranti and the local community. ●

NEW Publications

3-D Seismic Interpretation*

M Bacon, R Simm and T Redshaw (Cambridge University Press, The Edinburgh Building, Shaftesbury Road, Cambridge CB2 2RU, UK. T: +44 (0)1223 312393; F: +44 (0)1223 315052; www.cambridge.org*). ISBN 0 521 79203 7. 212 pages. Price (hardback): £80.*

3-D seismic data have become the key tool used in the oil and gas industry to understand the subsurface. The aim of this book is to help geophysicists and geologists new to the technique to interpret 3-D data while avoiding common pitfalls. Topics covered include basic structural interpretation and map-making; the use of 3-D visualisation methods; interpretation of seismic amplitudes, including their relation to rock and fluid properties; and the generation and use of AVO and acoustic impedance datasets. Also included is the increasingly important field of time-lapse seismic mapping, which allows the interpreter to trace the movement of fluids within the reservoir during production. The acquisition and processing of 3-D seismic data is also discussed. Extensive mathematics has been avoided, but enough detail is included on the effects of changing rock and fluid properties to allow readers to make their own calculations.

* *Held in EI Library*

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- *Energy Policies of IEA Countries: Switzerland 2003 Review.* IEA OECD, Paris, France, 2003. ISBN 9264014780.
- *Handbook on Nuclear Law.* Carlton Stoiber, Alec Baer, Norbert Pelzer, Wolfram Tonhauser. IAEA, Vienna, Austria, 2003. ISBN 9201057032.
- *The Eve of the Petroleum Era: Key Issues of the History of Russia's and US Oil Industries in the Second Half of the 19th and Early 20th Century.* Dr Sc Vagit Alekperov (ed.) Russian Academy of Natural Sciences, Moscow, Russia, 2003. ISBN 5935460606
- *The HCB Tank Guide 2003/04: Directory of the Tank Container and Road Tanker Industries Worldwide.* 11th ed. HCB, Informa Maritime & Transport, 2003. ISBN 1843111071.

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