Petroleum review

SEPTEMBER 2003

North Sea

- Straining to slow the production declines
- Exploration beyond 2003 on the UKCS
- Impact of new entrants in the UK sector

Subsea

- Strong growth in subsea sector

North America

- US energy security in the 21st century

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

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IP WEEK 2004
16 – 19 FEBRUARY
LONDON

in association with

Petroleum review

publishers of IP Week 2004 daily

Energy Intelligence

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IP Week is the focal point in Europe each year for leading oil and gas industry professionals. It offers an intensive round of conferences, seminars, industry and trade association events, oil industry's largest Annual Dinner and Annual Lunch.

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- Gas
- Exploration
- Oil and gas in FSU
- Transportation security
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Tuesday 17 February, Dorchester Hotel, London

The Annual Lunch provides a unique opportunity to hear one of the world's senior figures in today's oil and gas industry discuss the key issues facing the industry in the context of the changing economic, social and political environment.

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Wednesday 18 February,
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The 90th Annual Dinner is a unique event in the international petroleum industry, which brings together over 1000 of its leading figures, and provides an opportunity to meet with old friends and acquaintances.

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John Simpson CBE, BBC World Affairs Editor

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Maximise on business and promotional opportunities connected with IP Week 2004 by participating in the oil and gas information services exhibition. The exhibition will be held alongside 2004 events.

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For more information on IP Week 2004, contact the Events Department at the Energy Institute:

T: +44 (0)20 7467 7100 e: events@energyinst.org.uk or visit: www.ipweek.co.uk

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A charitable company limited by guarantee
61 New Cavendish Street, London W1G 7AR, UK
Chief Executive Designate: Louise Kingham
General Enquiries:
T: +44 (0)20 7467 7100
F: +44 (0)20 7255 1472

EDITORIAL

Editor: Chris Skrebowski FEI
Associate Editor: Kim Jackson
Design and Print Manager: Emma Parsons

Editorial enquiries only:
T: +44 (0)20 7467 7118
F: +44 (0)20 7637 0086

e: petrev@energyinst.org.uk
www.energyinst.org.uk

ADVERTISING

Advertising Manager: Hootan Sherafat
McMillan Scott plc
10 Savoy Street, London WC2E 7HR

T: +44 (0)20 7878 2300 F: +44 (0)20 7379 7155
e: petroleumreview@mcmslondon.co.uk
www.mcmillan-scott.co.uk

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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: Saipem crane-barge *S7000* completed installation of Statoil's Kvitebjørn platform earlier this year. Start-up is scheduled for October 2004
Photo: Statoil/Rune Johansen

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ROUNDUP

From the Editor

North Sea decline and US power collapse

This issue features our annual review of the North Sea production and future development projects. Unfortunately, it makes fairly gloomy reading. Overall North Sea oil production (p12) peaked in 2000, as did gas production in the dominant UK sector. Looking forward, the only area of continued expansion is Norwegian gas production.

A more positive view of North Sea prospects is to be found in the impact of the new entrants to the UK sector of the North Sea, who are picking up the assets that the oil majors are selling off (p30). Future drilling prospects could also be rather better than generally supposed (p18).

The real problem (or in the contemporary usage – challenge) is that for virtually the whole period from 1975 to 2000 expanding North Sea production provided a check to Opec's ability to drive oil prices higher. In the 25 years to 2000 North Sea production increased in 22 of the years, accounting for the bulk of the global increase in no less than eight of the years. In 1984, 1994 and 1995 the increase in North Sea production exceeded the increase of all Opec producers combined. The North Sea can no longer perform this role as oil production from the area peaked in 2000.

The key question now is whether the current production stars – Russia, Kazakhstan, Canada, Angola and Brazil – will be able to perform this price moderating role? Or will Opec's power wax as booming oil revenues make it easier to restrict production flows to maintain prices?

In this context the continuing sabotage of Iraq's oil infrastructure, social unrest in Nigeria and mounting doubts about Venezuela's ability to sustain production capacity means that we should all pray that the upcoming winter is mild, particularly as oil stocks remain on the low side with the notable exception of crude in the Far East.

The recent devastating collapse of power supplies in North America, the full explanation for which is still unknown, is being seen as a major wake-up call.

The immediate cause appears to have been some form of overload in Ohio that took down power transmission, initiating a ripple collapse as transmission capacity and generating capacity was tripped out and shutdown.

The good news is that all the shutdown procedures appear to have worked well and safely, with eight nuclear units having shutdown without problems or incidents.

The latest power crisis following the Californian crisis of 2000–2001 has re-ignited the somewhat arid debate between advocates of privatisation and decontrol, and those who favour controls and dirigiste planning. There seems little doubt that decontrol of generation has lowered electricity prices and led to more rational investment planning, with companies able to buy and sell electricity to allow them to optimise investment timing.

The weakness has been that they have overwhelmingly elected to build combined cycle gas turbine (CCGT) plants, but appear to have been caught out by the gas supply crisis which has produced high prices and restricted supplies – possibly for an extended period. Or they have elected to rely on buying supplies (often hydro) from oversupplied regions, without making appropriate investments in transmission capacity.

The television and media are currently full of graphs showing the rising US demand for electricity and the declining investment in transmission capacity. Currently promoted candidates for blame appear to be excessive competition (not enough money for investment), Enron (banks reluctant to loan to electricty companies), 'Nimbyism' (no new pylons near me), corporate greed (the system will probably hold up – no need for spending) and inappropriate or ineffective regulation.

Perhaps the oil industry has some lessons to offer. Western oil companies are overwhelmingly privately owned. They are subject to only limited regulation in terms of supply and distribution. However, the oil industry has been supremely successful at delivering society's most vital energy resource consistently and reliably. Oil can be stored, unlike electricity, so to improve supply security governments have mandated strategic storage, which neatly deals with the possibility that private companies would tolerate greater supply risks than governments are prepared to accept. The electricity equivalent would be mandatory spare generating capacity. Difficult, but not impossible to organise.

The challenge of transmission capacity is, however, rather greater. The parallel here is with common carrier pipelines versus access to privately-owned pipelines. The trick is to ensure a fair return to the investors without overly benefitting the non-investor. Current conventional wisdom favours the common carrier solution. Maybe this is unwise.

Chris Skrebowski

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

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e world

This month the Energy Institute (EI) will unveil its new website at **www.energyinst.org.uk** that will bring together the activities of both the Institute of Petroleum (IP) and the Institute of Energy (InstE).

With background information on the EI and its business objectives, **www.energyinst.org.uk** should be the first point of contact for all those working within the energy industries. Providing details of the EI's technical, membership, events, library and information services, publications and journals, training and education activities, the site offers an opportunity for members to familiarise themselves with the Institute's main products and services.

The website also provides a comprehensive service to anyone looking for assistance in making their next career move. With a detailed job-search facility for both national and international positions, powered by **monster.co.uk**, this careers service allows users to build their CV online and apply and track applications, whilst also receiving daily job alerts.

Education and training is a key focus of the EI and the website offers a range of resources to download for those currently studying or working in energy. Detailing the Institute's portfolio of education and training courses, including one-day short courses and distance learning diplomas, the site also provides links to other organisations providing useful resources and case studies.

The website also allows members to keep up-to-date with EI national and branch events. As a member you have the opportunity to become a registered user of the site and can access the 'Members Only' area that includes a number of useful sources of energy industry information and data.

The EI website is an information resource for the industry, relevant and useful to a wide range of individuals and organisations – not just those working or studying in the field but also those who need to draw on the Institute's collective expertise. To find out more, visit **www.energyinst.org.uk**

In Brief

NEWS Upstream

UK

Faroe Petroleum is in the process of *acquiring a 20% stake in the Laggan discovery in block 206/1a and a 17.5% interest in the Suilven discovery in blocks 204/14 and 204/15, all in the UK West of Shetlands offshore area. The combined reserves in Suilven and Laggan are put at 156bn cf of gas net to Faroe Petroleum.*

Energy Africa is to take a 20% stake *from Kerr-McGee in blocks 16/12b and 16/13d on the UK Continental Shelf for an undisclosed sum. A well is to be drilled in September/October 2003.*

Paladin Resources, one of the new *wave of independent North Sea oil and gas operators, has become the 29th member of the UK Offshore Operators Association (UKOOA).*

Petro-Canada has completed its acqui-*sition of a package of North Sea assets from Shell Expro for an undisclosed sum and further 1% equity for Shell in the Shell-operated Goldeneye field. The deal increases Petro-Canada's interest in the Guillemot West and North West fields to 90%, and in the* Triton *FPSO to 33.11%, making it the largest owner. The company has also taken Shell Expro's share in block 21/23b, containing the Grebe discovery, as well as its 50% stakes in block 21/30 South and 21/29b North, and its 33.156% interest in block 21/29b South East, as well as Shell's 30.806% and Esso's 25.806% stakes in block 21/29b South West – all of which contain fallow discoveries.*

Three hundred North Sea oil workers *are facing redundancy following the*

Complete news update

The 'In Brief' news items in *Petroleum Review* represent just a fraction of the news we regularly publish on the EI website @ **www.energyinst.org.uk** via the 'News in Brief Service', together with our daily News 'ticker' on the main home page.

Furthermore, those news stories marked with an asterisk (*) in the magazine are covered in more detail on the News in Brief Service.

Why not visit the site to find out more about the latest developments and trends in your industry? Click on

www.energyinst.org.uk

Promote licences prove popular

The UK Government has offered 88 new licences to 62 companies following the 21st offshore licensing round. A record 27 companies are new entrants to the area. The offer comprises 35 'traditional' offshore production licences and 53 of the new 'Promote' licences covering 137 blocks.

The new Promote licences offer the licensee the opportunity to assess and promote the prospectivity of the licensed acreage for an initial two-year period without the stringent financial, technical and environmental entry checks to be passed for a traditional licence. However, Promote licensees will not be approved as operator, and therefore will not be permitted to carry out exploration activity such as the drilling of wells, until they have passed those checks and made a firm commitment to complete an agreed initial term work programme. For the period of this assessment the licence rental fee will be 10% of the rental fee for the traditional licence.

A full listing of the successful applicants can be found at www.og.dti.gov.uk

Two additional 'out of round' offers have also been made to Talisman Energy and Encana on block 13/26b, and to Wessex Exploration on blocks 98/7b and 98/8a.

Tangguh LNG deal

The BP-operated Tangguh project in the Indonesian Province of West Papua is reported to have beaten the North West Shelf gas project to a 20-year contract to supply in excess of 1mn tonnes of LNG to South Korea's SK Corporation and Posco companies. The deal challenges the monopoly of gas imports held by the Korean Government-controlled utility KoreaGas. Pocso has also announced plans to construct an LNG receiving terminal at Gwangyang, with an annual production capacity of 1.7mn tonnes, due to be completed in June 2005.

Tangguh is seen as a major competitor to the North West Shelf project. Last year it secured a contract to supply 2.6mn t/y of LNG to a terminal planned in Fujian Province in China. Tangguh is also understood to have signed a deal to export to the US some 6mn t/y of LNG beginning in 2007.

Earlier this year, the North West Shelf project agreed a deal to supply up to 500,000 t/y of LNG to KoreaGas for seven years beginning by the end of 2003.

Faroes drilling update

Well 6004/17-1, drilled on behalf of Eni and the Faroes Oil and Gas Company in licence 002 by the drillship *Belford Dolphin*, did not show signs of oil or gas and is to be plugged and abandoned.

The Minister of Petroleum, Eyoun Elttør said: 'The result is disappointing, although not decisive for future exploration on the Faroe Shelf. More wells are to be drilled during the coming years where, hopefully, targets in deeper sediments will be taken into consideration.'

'Oil exploration on the Faroe Shelf will continue, and at present new work programmes for the nine-year licences are being negotiated by the Ministry of Petroleum and the licensees.

'At the same time the Ministry of Petroleum and the Faroese Geological Survey have started preparations for a second licensing round, and I anticipate a successful outcome of the oil exploration in the future.'

Norwegian nominations for licensing round

The Norwegian Ministry of Petroleum and Energy has received nominations from 14 companies regarding blocks to be included in the 18th licensing round on the Norwegian Continental Shelf (NCS). The nominating companies are: Norsk Agip, BP, ChevronTexaco, ConocoPhillips, Dong, ExxonMobil, Gaz de France, Idemitsu Petroleum Norge, Marathon Petroleum Norge, Norsk Hydro, RWE Dea, Norske Shell, Statoil and Total. Two or more companies nominated 43 blocks. The Ministry will base the announcement of the 18th licensing round on the nominations.

The 18th licensing round will give the companies access to frontier acreage, which is important to increase the exploration activity and to achieve the long-term scenario, according to Einar Steensnæs, Minister of Petroleum and Energy. Simultaneously the government aims to balance the interests connected to the environment, fishery, fish farming and petroleum activities within the frame of a sustainable development.

The blocks are expected to be announced in 2H2003. Awards could then take place before summer 2004.

Zamzama Phase 1 comes onstream

Phase 1 of Pakistan's Zamzama gas development has completed nearly four months ahead of schedule and under the original $100mn budget. Phase 1 will triple the current gas processing capacity, facilitating the supply of up to 320mn cf/d of gas to Sui Southern Gas Company and Sui Northern Gas Pipelines over the expected field life of 20 years.

Three new development wells (Zamzama-3, -4 and -5) were drilled during this phase of development, and are tied into two new processing trains with a nameplate capacity of 140mn cf/d each. A fourth well (Zamzama North), designed to further appraise the field, is nearing completion. First production from the Zamzama field commenced in March 2001 via an extended well test fed by two wells, and has supplied on average 100mn cf/d of gas to Sui Southern Gas Company under a 21-month contract.

The core area of the Zamzama field has estimated proven and probable reserves of 1.7tn cf, with significant additional reserves potential outside the area.

Project partners are BHP Billiton (38.5%), Pakistan Government (25%), Kufpec/Premier Oil joint venture PKP Exploration (18.75%) and Eni (17.75%).

Sunrise considers onshore LNG option

Although the preferred option for the export-oriented Sunrise gas project in the Timor Sea is the world's first floating LNG (FLNG) facility based on Shell technology, the partners are reported to be once again assessing the potential for an onshore LNG development in Darwin. It is thought the plant could be located either at ConocoPhillips' $1.6bn LNG export facility at Wickham Point, currently under construction, or at a new proposed industrial site at Glyde Point.

At the end of last year, Shell, Woodside and Osaka Gas were reportedly in favour of the FLNG to serve growing gas demand from the North Asia market, arguing that such a solution could save up to $2bn in costs. However, the Northern Territory Government wanted the Timor Sea gas to be brought onshore at Darwin in order to encourage downstream industry development.

ConocoPhillips' commitment to the $1.6bn Wickham Point LNG export facility in June this year – which will supply Tokyo Electric and Tokyo Gas with 3mn t/y of LNG for 17 years beginning in early 2006 as part of the second phase of development of the 3.3tn cf Bayu Undan reserves in the Timor Sea – has altered the Sunrise project's economics so that an onshore solution may now be economically viable. In addition, Sunrise reserves have been progressively downgraded to about 7.7tn cf, well below the 10tn cf level orginally deemed necessary to support the LNG supply contracts over 25 years.

Kerch farm-in

Indusmin Energy of Canada has raised $2mn from a farm-in to the Kerch project in Ukraine by local company Kyiv Energy. Kerch comprises six fields in southwest Ukraine, two in the west of the licence and four in the east, with recoverable reserves put at 180mn boe. None of the four fields in the east of the concession are currently producing. However, one makeover well in the western part has tested at 40,000 cm/d.

Indusmin, which has a 72% stake in Kerch, is to retain a 12.5% royalty interest of all gross revenues derived from the project over its first 15 years.

The money will allow Indusmin to pursue its interest in a separate licence in the Ukraine – the Malinovesky oil field in the west of the country. The work programme for a maximum of five wells was due to commence as *Petroleum Review* went to press.

Angolan discovery

ExxonMobil and Sonangol have made another deepwater oil discovery, the fourteenth on Angola block 15. The Clochas-1 discovery well flowed at 1,764 b/d. ExxonMobil now has in excess of 10.5bn boe reserves (gross) in Angola blocks 15, 17, 31, and 32.

Block 15 has the potential to recover more than 4bn boe (gross), according to ExxonMobil. Four major development projects are currently being progressed on the block, including the Xikomba project that will use an early production system to recover some 100mn barrels of oil. It is due onstream in late 2003. Also under development are the Kizomba A and B projects, each designed to recover approximately 1bn barrels of oil. First production is expected from Kizomba A in 2004, and Kizomba B in early 2006. Development planning for Kizomba C is under way.

In Brief

decision of Global Santa Fe to review its offshore operations. The company has announced plans to pull out of its drilling contracts on 12 fixed installations in the North Sea to concentrate on its mobile drilling operations.

Europe

***Cairn has disposed of all of its interests** in the Dutch sector of the North Sea through the sale of its subsidiary Holland Sea Search (HSS) to Dyas for $26mn.**

North America

***BHP Billiton reports that the Neptune-**5 appraisal well in the deepwater Gulf of Mexico Atwater Valley block 574 encountered a gross hydrocarbon column of nearly 1,200 ft, with more than 500 ft of net oil pay.**

***The Alberta Energy and Utilities Board** is reported to have upheld a controversial decision to shut-in more than 900 gas wells in a bid to protect untapped oilsands reserves in a move that may cost taxpayers hundred of millions in compensation to gas producers.**

***The Government of Bahamas is** reported to have signed an agreement with Kerr-McGee for the exploration of oil and gas in the Great Bahama Bank.**

***ConocoPhillips has announced a dis-**covery in the Lorien exploration well in the Gulf of Mexico on Green Canyon block 199. The well was drilled in 2,177 ft of water and encountered more than 120 ft of hydrocarbons in a high-quality reservoir interval.**

Middle East

***Syrian Oil Company has discovered** 1.2bn cm of gas reserves in central Syria, according to Oil Minister Ibrahim Hadded. The field is expected to yield up to 300,000 cm/d of gas, reports* Stella Zenkovich. *The country currently produces some 22mn cm/d of gas.*

***The Indian Oil Corporation and ONGC** Videsh have joined with global oil majors BP and Occidental to bid for a Kuwaiti oil field production contract. The BP-led consortium is one of three groups bidding for 'Project Kuwait', which aims to develop the Raudhatain, Sabriyah, Ratqa and Abdali fields in the north that cur-*

In Brief

rently produce 450,000 b/d of oil. Kuwait wants to increase this to 900,000 b/d by mid-2005. The other contenders are a consortium led by ChevronTexaco, and another led by Shell. Sibneft is also reported to have joined one of the bidding consortiums.

Gazprom and Uzbekneftegaz are reported to be planning to jointly develop reserves in the Ustyurt region of Uzbekistan, to produce some 2.5bn cmly of gas that will be exported to Western Europe.

Abu Dhabi National Oil Company has awarded a $300mn contract to upgrade facilities at the Bu Hasa oil field to Snamprogetti. This comprises installation of a 730,000 b/d degasification plant and replacement of two existing gas separators, each of 50,000 b/d with four new separators. Completion is slated for 1Q2006.

Russia & Central Asia

The Russian Ministry of Energy has reported strong year-on-year production growth of 11% for the first seven months of 2003. The leaders were Sibneft and Yukos, producing 610,000 b/d (up 22.6%) and 1.573mn b/d (up 19.2%) respectively. TNK production rose 10.9% to 831,000 b/d; Surgutneftegaz 10.2% to 1.056mn b/d; Slavneft 9.2% to 344,000 b/d; Rosneft 3.3% to 328,000 b/d; and Lukoil 3% to 1.55mn b/d.

Sakhalin Energy has awarded a $1.2bn contract for onshore pipelines as part of Phase 2 of the Sakhalin 2 project to a consortium comprising Russian companies Starstroi and Lukoil-Neftegazstroi as well as European companies Saipem and Amec.*

China National Petroleum Corporation (CNPC) is rumoured to have acquired a 35% stake in Kazakhstan's North Buzachi field from ChevronTexaco and is thought to be in negotiations regarding the remaining 65%. The field is currently producing 8,000 b/d but has enormous potential as reserves are put at 1.8bn barrels.

BP is planning to commence its first well in a $200mn exploration project near the Sakhalin Islands in 2004. BP is financing the whole of the exploration costs although it only holds a 49% stake in the project, the remainder being held by state-owned Rosneft.

NEWS Upstream

Demand key to sustainable UK recovery

UK oil production remained below 2mn b/d (1,934,653 b/d) in May, although there was a rise of 0.6% compared with April, according to the latest Royal Bank of Scotland *Oil & Gas Index*. The previous six weeks had seen oil prices remain stable compared to the volatility of the previous 12 months, with oil prices averaging $28.04/b since the start of June.

'Oil prices have remained remarkably stable during the past six weeks, with markets still being influenced by sentiment,' said Tony Wood, Senior Economist, The Royal Bank of Scotland Group. 'Recovery in demand is key to more sustainable recovery in global oil industry investment. We expect muted demand recovery through the second half of this year, which should see a more positive investment climate in 2004. Global oil stocks are currently relatively low and with the demand situation improving prices look set to stay relatively high over the coming months.'

Gas output also fell in May – at 9,966mn cf/d down 10.6% on the month and 2.6% compared to May 2002.

Weaker oil prices in May saw a fall in oil revenues to an average of £30.51mn/d, down a massive 16.9% on the previous year and 9.2% down on April.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
May	2,106,088	10,227	25.50
Jun	2,142,356	9,128	24.10
Jul	1,938,677	7,569	25.70
Aug	1,831,386	8,744	28.40
Sep	2,001,329	8,699	28.40
Oct	2,133,641	10,611	27.60
Nov	2,165,277	11,276	24.20
Dec	2,257,244	12,114	28.30
Jan 2003	2,158,924	12,114	31.20
Feb	2,086,517	12,374	32.20
Mar	2,104,855	13,015	29.90
Apr	1,922,505	12,155	27.50
May	1,934,653	9,966	25.60

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Gorgon gas deal to supply US demand

ChevronTexaco has announced that an affiliate has signed a Memorandum of Understanding (MOU) with the Gorgon joint venture in Australia for the supply of LNG for distribution to markets on the West Coast of North America. Under terms of the MOU, a ChevronTexaco affiliate will enter into negotiations, the details of which are confidential, with the venture which could lead to the supply of at least 2 mn t/y of LNG over a 20-year period, beginning in 2008. The Gorgon gas field, located offshore Western Australia, has certified proven hydrocarbon reserves of 12.9tn cf, with total natural gas resources in the Greater Gorgon area exceeding 40tn cf. The Gorgon joint venture participants include ChevronTexaco (4/7th interest and operator), Shell (2/7th interest) and ExxonMobil (1/7th interest).

'Growing North American demand for natural gas is widely projected to outstrip supply capabilities,' said John Gass, President of ChevronTexaco Global Gas, which coordinates the company's worldwide natural gas businesses. 'The Gorgon joint venture is well positioned to help satisfy natural gas demand in both the West Coast of the US and Mexico.' ChevronTexaco is currently seeking approvals to permit the construction and operation of an LNG terminal and regasification facility offshore Baja California, which would be capable of receiving Gorgon LNG. The company is also engaged in permitting another LNG import terminal facility offshore Louisiana in the Gulf of Mexico, and is evaluating additional sites suitable for imports of LNG to North America.

Shell has also agreed to purchase up to 2mn t/y of LNG from the Gorgon joint venture for its proposed 7.5mn t/y Ensenada LNG import terminal in western Mexico. The new terminal is expected to be commissioned in 2007.

NEWS Upstream

Innovation brings Zhao Dong onstream

Apache Corporation and partner PetroChina have brought onstream their shallow-water Zhao Dong field in Dagang, Bohai Bay, China, at the rate of 6,000 b/d of oil from three wells. Production is expected to peak at 22,000 b/d by 1Q2004.

The offshore infrastructure at Zhao Dong includes two large platforms, each weighing 6,000 tonnes, claimed to be the largest ever fabricated in China. Construction of the platforms is also reported to have been completed with a world-class safety record – just two lost-time incidents in 2mn man-hours.

The initial drilling phase of the project included 17 wells drilled primarily to the Guantao formation. Once completion operations are finished on these wells, drilling will resume to develop additional Guantao and Minghuazhen reservoirs. Drilling results to date have identified several new reservoirs.

The initial drilling phase was very efficient, state the two companies, incorporating a number of innovative techniques never before used in Bohai Bay, such as batch drilling and casing processes to enhance use of rig time and resources. Drilling with casing was used for the surface casing with world-record results for drilling penetration rates. The process greatly reduced drilling and casing time and the associated costs.

Chad–Cameroon project commissioned

ChevronTexaco has confirmed first oil from the Chad-Cameroon Oil Development and Pipeline Project and the start-up of pipeline fill activities. Production of approximately 225,000 b/d is anticipated when central treating facilities and drilling operations are completed. ChevronTexaco is a 25% partner in the project consortium.

Completed one year ahead of schedule, the pipeline will transport landlocked oil 660 miles from the Bolobo, Miandoum and Kome oil fields, near Doba, in southern Chad, through eastern Cameroon and on to an export terminal facility at Kribi, Cameroon, in the Gulf of Guinea. There the oil will be transshipped from an FSO vessel for export to world markets.

Pipeline proposal to carry Kovykta gas to Asia

A proposed pipeline to carry gas from Siberia's large Kovykta gas field to South Korea and China is forecast to cost some $11bn, according to South Korea's Finance Ministry. Partners in the project include Kogas, Rusia Petroleum and CNPC. The Kovykta field has reserves put at 840mn tonnes of gas and is thought capable of supplying 7mn t/y of gas to South Korea for 30 years, also supplying 14mn t/y to China. The field could come onstream as early as 2008.

South Korea is almost entirely dependent on imports of oil and gas for its energy requirements, while China is endeavouring to diversify its supply sources as domestic consumption grows to satisfy a rapidly growing economy.

UK onshore oil find

Pentex Oil UK's Avington-2 well on farmland near Winchester in Hampshire has discovered oil in a structure that is understood to have mapped volumes in excess of 100mn barrels. The find has been reported as one of the most important on the UK mainland in the past 20 years. Pentex Oil holds 50% of the block and will act as operator, the remaining interest being held by Egdon-Resources, Sterling-Resources, YCI and Northern Petroleum.

The find represents success at the first attempt for Bank of Scotland financed Pentex Oil UK, owned by Jeff Graham and Russell Jordan, who in May last year led the $35.35mn management buyout of the Pentex Energy Group of companies from AIM-listed Sibir Energy.

Working Time Directive

The UK Offshore Operators Association has confirmed that it complies with the Working Time Directive that entered in to force offshore on 4 August 2003. The Working Time Directive sets out legal requirements to protect workers from excessive working hours. It means that workers should work no more than 2,304 hours per year. A typical work pattern of two weeks offshore followed by two weeks onshore, or 26 weeks on, 26 weeks off per annum, means that most offshore workers currently work in the region of 2,000 hours per year. Background information on the industry's compliance with the Working Time Directive can be found at www.oilandgas.org.uk/ukooa/newpublications/srchResults.cfm

In Brief

Asia-Pacific

***The BG Group and its Indian partners** are reported to be planning to invest $490mn to increase oil production from fields offshore India by 5,000 b/d, from the current 25,000 b/d, and gas output from 8mn cm/d to around 10.5mn cm/d.*

***Cairn is to acquire all of the upstream** assets and undertakings of Shell in Bangladesh, including a 37.5% operated interest in the Sangu development area (SDA), increasing its total stake to 75%.**

Latin America

***Shell (80%) has announced first pro**duction from the Bijupira-Salema fields in the Campos Basin offshore Brazil. Initial production of 20,000 b/d of oil is expected to peak at 80,000 b/d and 35mn cf/d of gas once all eight wells are onstream. The project's* Fluminense *FPSO, which is operated by MODEC International, has an oil processing capacity of 81,000 b/d of oil, gas handling of 75mn cf/d, water injection of 92,000 b/d and storage capacity of 1.2mn barrels.*

Africa

***PetroSA's Sable oil field has come** onstream, producing some 30,000–40,000 b/d. The field is expected to produce between 20mn and 25mn barrels of oil over the next three years, with a possible life of up to five to six years. Field production will replace up to 11% of South Africa's current oil import requirement of 370,000 b/d.*

***The ExxonMobil subsidiary Mobil** Equatorial Guinea Inc (MEGI) has started production from the Southern Expansion Area (SEA) of the Zafiro field, in block B offshore Equatorial Guinea. The project is expected to recover more than 150mn barrels of oil. Production via the field's FPSO is forecast to add about 110,000 b/d to current Zafiro production, increasing total field capacity to 300,000 b/d.*

MANY OF THE MONTH'S UPSTREAM NEWS STORIES NOT INCLUDED ABOVE CAN BE FOUND ON THE NEWS IN BRIEF SERVICE @ www.energyinst.org.uk

In Brief

UK

Strong oil prices in the wake of the *Iraq war have helped push profits 42% higher at BP. The company posted profits of $3.12bn (£1.95bn) in April, May and June, up from $2.19bn a year ago. The figure represented a drop from its record profits of $3.73bn in the first three months of the year.*

Shell has reported strong 2Q2003 *results, with a net income of $2.8bn, a rise of 28% – bringing net income for the half-year to $8.2bn, a rise of 82%.*

BG Group, which reported a 38% rise *in second quarter profits, is confident that it can meet its 2003 production target of 440,000 boe/d, up some 20% on 2002.*

Europe

Total has posted a 1H2003 net income *of 3.73bn, up 27% from 1H2002.*

BP has taken delivery of the first cargo *to the recently completed LNG import and regasification terminal in Bilbao, northern Spain. The facility will handle up to 6bn cm/y of gas.**

Shell Wind Energy has acquired a 40% *share of the La Muela Wind Park in north-east Spain from TXU Europe Energy Trading for an undisclosed sum.**

Eni has acquired a 50% stake in Unión *Fenosa Gas for €440.8mn.*

North America

Technip has signed a contract for the *front-end engineering design (FEED) leading to the finalisation of the engineering, procurement and construction (EPC) contract for Freeport LNG Development's LNG receiving terminal to be located on Quintana Island near Freeport, Texas.*

ExxonMobil posted a 2Q2003 net *income of $4,170mn, up $1,530mn from 2Q2002. ChevronTexaco announced a net income of $1.6bn for the quarter (2002: $407mn). Petro-Canada reported a 2Q2003 profit of C$588mn; Anadarko $301mn; Unocal $177mn (2002: $114mn); Talisman Energy $210mn (2002: $90mn); ConocoPhillips $1.14bn; Amerada Hess $252mn (2002: $149mn); Imperial Oil $513mn; and Apache $243mn (2002: $143mn).*

NEWS Industry

World first for fuel-grade methanol plant

PetroWorld, together with partners Tranworld Exploration, Foster Wheeler and Starchem Technologies, has announced that it is developing what is claimed to be the world's first floating large-scale, fuel-grade methanol plant designed to extract natural gas from reserves in remote areas and convert it on board into liquid methanol at a rate of 12,000–15,000 t/d of output. A primary market for the product is gas turbine power plants in the US.

The $700mn plant is to deployed offshore Africa's west coast about three years from the date that project details and financing are finalised.

The partnership hopes to develop and deploy additional plants in 'appropriate maritime locations around the world' that have stranded gas. The world's proven natural gas reserves are in excess of 5,000tn cf, enough to satisfy one-third of total global oil demand for 35 years. However, half of these gas reserves are 'stranded', located off the shores of countries where it is uneconomical to build LNG facilities on shore, not to mention the cost of transportation in specially refrigerated tankers as no pipeline system exists.

The floating methanol plant is considered an 'ideal' solution to developing these stranded reserves as it eliminates any onshore investment and liquid methanol can be transported in ordinary tankers.

Russian & Central Asian developments

Stella Zenkovich reports on recent developments in the Russian and Central Asian oil and gas sector.

- The feasibility study for the proposed $1bn Constanta–Trieste pipeline, intended to carry 40mn t/y of Caspian oil to Europe, was to be finalised by late August by HLP Parsons of the US. This is to be followed by fund-raising efforts by Romania and Croatia. The pipeline is expected to link Constanta port on the Black Sea with Serbia's Pancevo Danube port and Croatia's Omisalj port, with a further link to Trieste in Italy.
- Turkmengaz has signed a contract with Canadian Thermo Design, authorising it to build by June 2004, on a turnkey basis, a third facility for LNG production at the Nayyip gas deposit in eastern Turkmenistan. Financing will be provided from the Turkmen State Fund.
- VNG, Germany's second largest gas importer, is planning to raise its stake in Polish gas/heat distributor Petraco from 49% to 92.1% and to undertake a restructuring programme prior to Poland's entry to the EU. Petraco supplies 40 cities in Poland via a 900 km-long pipeline grid.
- Overgas will remain the sole provider of Russian gas in Bulgaria, the price of which may fall by 10%, Energy Minister Milko Kovachev recently announced.
- Bosnian Serb Republic Prime Minister Dragan Mikerevic has asked the European Bank of Reconstruction and Development (EBRD) to participate in the privatisation of the country's oil industry.

Call to halt US SPR top-ups until oil price falls

Despite low oil supplies, the US Government is reported to have been pumping millions of barrels into its emergency reserve, which some analysts argue has contributed to a surge in crude prices and kept gasoline costs high. The US Energy Department, however, discounts the impact of the purchases, stating in early August that while 11mn barrels of oil were being diverted from oil markets into the Strategic Petroleum Reserve (SPR) since the beginning of May, commercial inventories during the same period were declining by 10mn barrels.

Nevertheless, Senator Carl Levin is understood to have urged Energy Secretary Spencer Abraham to suspend the oil shipments 'until the price of oil falls from its current high levels and the private sector inventories increase'. The 700mn-barrel capacity reserve currently stands at 611mn barrels.

NEWS Industry

UK consultation on emissions trading scheme

The UK Government has issued a consultation on the new European Union Emissions Trading Scheme (ETS), which will come into effect in January 2005. The consultation covers a number of issues including:

- the method on how the UK's overall cap should be distributed to individual installations;
- how new entrants and closed installations should be treated; and
- what proportion of allowances should be allocated each year.

The Greenhouse Gas Emissions Allowance Trading Directive requires member state governments to set a cap on the total allowable carbon dioxide emissions from installations covered by the scheme. The UK Government must prepare its National Allocation Plan by 31 March 2004, which sets out how many allowances it intends to allocate to UK installations and how it proposes to allocate these allowances.

The trading scheme – which will cover the power generation sector, mineral oil refineries, offshore installations and other heavy industrial sectors – is a key component of the UK's long-term environmental and energy targets. The Energy White Paper published in February set the target of reducing greenhouse gases by 60% by 2050.

The scheme will start on 1 January 2005, with the first phase running until 31 December 2007. The second phase will run from 2008–2012 to coincide with the first Kyoto Commitment period. Further five-year phases are expected subsequently.

The consultation suggests what methods should be used to distribute allowances for individual installations and businesses. This work will go towards devising the National Allocation Plan, which will be consulted on in more detail later in the year.

Further information is available at **www.defra.gov.uk**

Focus on Centrica/Dynegy merger

UK Trade and Industry Secretary Patricia Hewitt has accepted the conclusions of the Competition Commission (CC) and the advice of the Office of Fair Trading (OFT) that the completed acquisition by Centrica of Dynegy Storage and Dynegy Onshore Processing 'may be expected to operate against the public interest'. She has asked the OFT, together with regulatory watchdog Ofgem, to seek to obtain by 1 December 2003 undertakings from Centrica to implement the wide-ranging package of behavioural remedies recommended by the CC.

The CC's report, which focused on the Rough gas storage facility, concluded that competition in the markets for flexible gas and domestic gas would be weakened by the merger, with the likely result that prices would be higher. It also suggested that innovation and investment at Rough would be lower as a result of the deal.

Shell to build its largest wind farm to date

Shell Wind Energy is to build its largest wind farm to date at a site 90 miles south-east of Lubbock, Texas, in Scurry and Borden counties. The 160 MW project, to be constructed in a 50:50 joint venture with Padoma Wind Power, is due to be completed by the end of this year. Total output from the Brazos wind farm will generate enough electricity to power approximately 30,000 homes. The wind farm is being developed by Cielo Wind Power and Orion Energy. TXU Energy has agreed to purchase electricity generated by the wind farm and has entered into a retail electricity arrangement with Green Mountain Energy Company. Shell Wind Energy will be the operator.

In Brief

Middle East

Israel Electric Corporation (IEC) is negotiating *for additional gas supply with US-Israeli joint venture Yam Thetis until a further supplier can be brought in, writes* Stella Zenkovich. *At present IEC is to receive 18bn cm over 11 years under a 2002 agreement, with first shipment due at Ashdod power station in October. Egypt was expected to furnish a similar amount, but opted out over Israel's handling of the Intifada. The plan is to substitute 1.5bn cm/y of gas from BG's operations in the Palestinian-ruled Gaza Strip.*

Mitsubishi is understood to be buying *up to 6mn barrels of oil from Iraq over a five-month period beginning in August. BP and Shell earlier agreed to take 10mn barrels from August to December. Iraq's State Oil Marketing Organization has also agreed to sell 6mn barrels under shorter spot contracts to ChevronTexaco, Petrobras and Vitol of Switzerland, each company to take 2mn barrels by the end of July.*

A new \$1bn, 270-km subsea gas *pipeline linking Jordan and Egypt has been officially inaugurated. It will allow Jordan to receive 1.1bn cm/y of Egyptian LNG and is expected to generate \$70mn in revenue for Egypt within the first year.**

Iran is reported to be studying two gas- *to-liquids (GTL) projects with Sasol and PetroSA, worth some \$2.2bn in total.*

Russia & Central Asia

The Russian Government is reported to *be considering raising export duties on natural gas to 30%.*

The Karachganak gas processing plant *has been officially opened and the connecting pipeline for the transportation of liquid hydrocarbons from the Karachganak oil, gas and condensate field to Atyrau, where they enter the Caspian Pipeline Consortium's facilities, has been put into operation. Field reserves are put at 1.2bn tonnes of liquid hydrocarbons and 1.3tn cm of natural gas. Lukoil holds a 15% stake in the project.*

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In Brief

UK

***Greenergy's GlobalPetrol – a blended** fuel comprising of up to 5% bioethanol and ultra low sulphur petrol – was recently road tested for the first time in race conditions in a Group N Subaru rally car at the 68 stage miles Swansea Bay rally, part of the ANCRO/Kumho Tyres National Rally Championship. Co-driven by Andrew Owens, CEO of Greenergy, and sponsored by British Sugar, who supplied the bioethanol component for the GlobalPetrol used, the car won its group class and finished fourth overall. GlobalPetrol is expected to be available for general forecourt sale from January 2005.*

***Stephen Timms, UK Minister for** Energy, has granted consent to Coalpower for the construction of a 430-MW coal-fuelled power station at Hatfield Colliery, Doncaster.*

***Furmanite International has signed a** federal agreement with BP to undertake all maintenance work for leak sealing and associated services on BP's onshore refining and processing facilities for the next five years. The contract will initially cover the oil company's Grangemouth, Coryton and Hull sites. It is planned to extend the coverage to other sites in continental Europe in due course.*

***BP is reportedly considering building a** reception terminal for LNG at its Coryton, Essex refinery.*

***Texaco is reported to be planning to** shed more than 100 jobs at its Pembroke oil refinery, which provides a fifth of all petrol used in Britain, over the next two years. Redundancies are due to begin at the end of this year and will continue into 2004.*

Europe

***AEM is to increase its interest in Italian** generator Edipower to 16% from 13.4%.*

***OMV and Yukos have signed a** Memorandum of Understanding covering the supply of up to 5mn t/y of crude oil to OMV's Schwechat refinery in Austria. The oil will be carried via a new 60-km pipeline that is to be constructed from Bratislava in the Slovak Republic to Schwechat at a projected cost of some €28mn. The pipeline is to*

NEWS Downstream

UK to introduce Renewable Obligation scheme

The introduction of the Renewable Obligation Certificate (ROC) scheme in the UK will place an additional annual cost on UK electricity supply companies, according to a recent report from the Standard & Poor's Ratings Services. 'Unless such costs are passed through to the end-user, the financial strength of supply companies could be negatively affected, irrespective of whether they opt to buy ROCs or be subject to a buy-out cost penalty,' said S&P credit analysis Paul Lund. 'Furthermore, the annual costs associated with the ROC scheme will increase in steps to 2010, by which time the obligation to provide renewable electricity will have increased to more than 10% of supply volumes.'

ROCs are part of the government's Renewable Obligation scheme, which came into force in April 2002. The scheme is designed to encourage the building of new renewable plants in the UK. Under the Obligation, electricity suppliers have to ensure that a proportion of the electricity they sell comes from 'green' sources. The proportion of electricity generated from green sources increases each year. By 2010, 10% of electricity should come from renewable sources. ROCs are proof of the purchase of green power and are used by suppliers to show that they have fulfilled their supply obligation.

The buy-out charge proposed under the ROC scheme represents a financial obligation that must be paid to the industry regulator, the Office of Gas and Electricity Markets (Ofgem), by a supply company if it does not hold enough ROCs to cover its renewable obligation in a given year. This creates an economic incentive for suppliers to either build ROC-accredited renewable generation capacity or acquire ROCs, which also carries negative cash flow implications.

Investment in new ROC-accredited projects in order to offset the buyout charge, however, would result in increased capital expenditure, which could further stretch the financial profiles of those utilities. In addition, the revision of asset values to reflect market movement away from older technology and toward more environmentally acceptable forms of generation could result in more indirect costs.

The utilities reported to be most directly affected by the buy-out liability are those with a significant presence in the UK electricity supply market, including Innogy, Powergen UK, Scottish Power, Scottish and Southern Energy, Centrica and EDF Energy. Generators including British Energy and other merchant independent power producers, however, could also be affected if they have direct supply agreements with industrial and commercial customers.

Downstream Russia & Central Asia

Stella Zenkovich reports on recent downstream developments in Russia and Central Asia:

- Rafineria Gdanska (RG), part of the Lotos group, has been valued by analysts as being worth between $500mn and $600mn in the light of last year's profit. The still-valid $225mn Rotch-PKN bid for the refinery is now expected to be refuted and a new tender to be called. Lukoil has already let it be known that this time it would participate. Meanwhile, Rotch is reported to be considering suing in case of bid scrapping for violation of tender rules through subjecting RG to structural change mid-stream and disclosure of the price bid.
- Lukoil-Bulgaria has opened its 90th filling station in the country in the Bragalevtsi residential district of Sofia, the 13th in the capital. The Russian parent's subsidiary is planning to add another 60 stations to its network by 2005.
- Yukos is to supply 2mn t/y of Siberian crude for processing at the Seidi refinery via an Iranian seaport and a pipeline going to Turkmenbashi. The pipeline has not been used since the Soviet disintegration, but now Yukos wants to repair it. The Seidi refinery has not been able to operate at full capacity since its completion.
- Lukoil is reported to have hired a Madrid-based energy consultancy to draw up a business plan for its entry into the Spanish market, which is advising it to either buy a stake in a smaller oil company or to open new filling stations in Spain. The move is part of an expansion plan in southern Europe.

Statoil electricity

Electricity will be supplied by Statoil to five major Norwegian companies in a further step forward for the group's current power market policy of focusing exclusively on the corporate sector. The new customers include food manufacturer Gro Industrier, paint specialist Jotun and brewer Grans Bryggeri, which collectively consume 78 GWh/y.

In addition come contracts with the Vest-Agder and Rogaland County Councils, which also make Statoil responsible for market sales of local authority power managed by the two counties. Running for up to two years with extension options, these deals commit Statoil Norge to meeting customer electricity requirements through direct purchases from the Nordic power pool – such deliveries were previously handled by local suppliers.

Irish cross-border electricity deal

BG Group's wholly-owned subsidiary Premier Power, the Northern Ireland-based power generation company, has agreed a major cross-border deal with Northern Ireland Electricity for 180 MW of electricity for onward supply to ESB, the Irish electricity company, through the North-South interconnector.

The three-year agreement, with an option to extend to another three years, represents a landmark in North-South energy trade and is claimed to be the first of its kind for major capacity export from Northern Ireland to the Republic of Ireland. It is a step closer to an all-island competitive energy market and will assist in matching the demand for power in the Republic of Ireland, which is forecast to grow at 3%/y over the lifetime of the contract.

Dutch electricity sector 'hots up'

Eighteen months after large business users in the Netherlands were given the right to choose their electricity supplier, competition in this sector is hotting up, reports independent market analyst Datamonitor.

Recent research reveals that approximately half of the country's major power users switched suppliers when their contracts were last up for renewal, and up to 60% switched at least once since market opening.

At a time when the choice of supplier is ever increasing, customers are not only switching in search of savings but are also driven away by poor service.

Datamonitor's survey also reveals that Electrabel and Delta lead the way, with the highest levels of customer service satisfaction.

Recent downstream developments in Africa

Stella Zenkovich **reports on recent downstream developments in Africa:**

- **The Government of Zimbabwe has stepped up efforts to set up a joint venture with Tamoil of Libya in a bid to end its four-year fuel crisis. According to Energy and Power Minister Amos Midzi, Tamoil-Zimbabwe would be a 50:50 joint venture between Tamoil and the National Oil Company of Zimbabwe (Noczim). Meanwhile fuel shortages persist. Deputy Minister Ode Reuben Marumahoko has said that state-owned Noczim will stop importing fuel when its restructuring is completed, with the private sector taking over imports for the Zimbabwean service station network. Domestic company Cumoil Private has already set up a $4mn facility and claims to have received 21mn litres of products at Beira port in Mozambique, which it plans to pump into Zimbabwe via its own pipeline. Mobil Mozambique is to transport 5,000 litres by land from Beira. Direct imports are also planned by local subsidiaries of BP, Caltex and Total.**
- **The Nigerian Government is making yet another attempt to privatise the country's four refineries, offering 51% equity in them to oil majors. Previous attempts have failed due to the poor condition of the four facilities and oil product prices being kept low in the country.**
- **CNPC is reported to be negotiating with the Sudanese Government an increase in the processing capacity of Khartoum refinery from 50,000 b/d to 80,000 b/d.**

In Brief

be commissioned by the end of 2005, with crude oil shipments beginning in January 2006 for an initial period of 10 years.

The independent market analyst *Datamonitor's latest report indicates that the forecourt is becoming a progressively more important outlet within a growing and increasingly consolidated convenience retail market. The company forecasts that the European convenience food and drinks market will grow by an average of 4.1% a year to 2007, compared with 2% for the overall retail food and drinks market. Meanwhile, the forecourt shop, as a convenience channel is growing even faster, with realised sales expected to rise an average 4.5% a year in the same period.*

Total has handed the IT systems oper*ation of its oil refining marketing activities to Cap Gemini Ernst & Young France.*

Eastern Europe

International Finance Corporation *(IFC) is reported to be considering the financing of an upgrade programme at the Petrotel Lukoil refinery in Romania. The modernisation programme is expected to cost some $97mn and would complete in 2004. The plant has a refining capacity of 4.7mn t/y.*

OMV reports that although it lost out *on taking a 25% stake plus on share in Croatian company Ina to Mol of Hungary, it is still targeting a doubling of its fuel retailing market position in central and eastern Europe by 2008. OMV currently holds a 12% market share, operating 1,736 service stations in 12 countries.*

North America

ConocoPhillips has completed a *transaction with Global Energy to acquire patents and intellectual property associated with the company's proprietary E-GAS Technology for Gasification. E-GAS is an advanced integrated gasification combined cycle (IGCC) gasifer technology that combines modern gasification with gas turbine and steam power generation technologies to produce electric power, as well as co-producing synthesis gas, hydrogen and steam. It is claimed to be among the cleanest,*

In Brief

most efficient commercial technologies for coal-based electric power generation.

Russia & Central Asia

Gazprom, the Russian gas monopoly, is *reported to have announced that it is ready to increase its bid for Lietuvos Dujos, a Lithuanian gas utility. Gazprom is the only participant in the bid, offering $26mn for the stake. However, the Lithuanian Government is understood to have asked the company to increase the bid. E.ON Energie paid over $37mn for a stake of the same size.*

Asia-Pacific

ConocoPhillips has signed an agree- *ment with Sinopec for a corporate-wide licence of ConocoPhillips' S Zorb Sulfur Removal Technology (SRT). Sinopec owns 25 refineries in China, with a total refining capacity of 2.6mn b/d of oil. Start-up for the first gasoline unit is targeted for 2005.*

Thailand's Agriculture Department *plans to expand palm oil tree plantations by 2mn rai to accommodate a new biodiesel fuel project worth 1.25bn baht. The project is designed to partly substitute imports of diesel which amount to 15bn litres and cost the country about 300bn baht each year.*

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NEWS Downstream

Improving UK electricity reference prices

Recommendations aimed at improving reference prices in the UK's wholesale electricity market were agreed at a recent meeting of the Power Trading Forum (PTF). The recommendations, for both day-ahead and month-ahead baseload reference prices, include:

- Reference prices should be based on actual trades not price assessments.
- The data source should be a centralised collection of transaction data from all electronic platforms (voice brokered trades subsequently entered on electronic trading platforms should be excluded).
- Price, volume and time data for all trades making up the reference prices should be made available.

Specific details on the mechanics of collection and publishing reference prices were not proposed as 'it was not the intent of the working group to prescribe a market solution'.

Energy savings

www.energylinx.co.uk **is a new home energy price comparison service that allows the domestic consumer to search all available UK electricity and gas prices quickly and simply online. The domestic consumer can search for energy supplies for their home by price or by green energy rating, using the Friends of the Earth Green Energy League. Domestic consumers can sign up online for their new energy supply – savings are reported to be averaging £134 per annum. For those wishing to carry out a comparative check only, the service saves the search for 90 days, automatically updating the results held should any price adjustments be made to the supply prices.**

The energylinx website also offers a free monthly newsletter on the UK and European power industry, as well as providing substantial information on energy efficiency and renewable energy. Domestic consumers can also sign up for information on any price changes affecting their home.

Record trading

The International Petroleum Exchange (IPE), one of Europe's leading energy futures and options exchange, has announced that July 2003 volumes surpassed previous July volume records. Brent Crude futures traded 1,972,165 contracts, a 13.8% increase over the previous July best, set in 2002. Natural Gas futures also surpassed the previous July record by 18.5%, also set in 2002, with 57,765 monthly and 150 quarterly contracts traded for a total of 57,915 contracts.

Total market volume set a July record. A total of 2,661,367 contracts changed hands, an increase of 5.1% over the previous July record, also set last year.

By the end of July 2003, over 14.25mn Brent Crude contracts had traded (7.25mn short of the Brent Crude total for 2002), and over 4.75mn Gas Oil contracts had traded (3.4mn short of the Gas Oil total for 2002). By July's end, total market volume stood at 19.6mn lots, some 2.2mn lots or 12.5% ahead of the comparable period in 2002.

UK Deliveries into Consumption (tonnes)

Products	†Jun 2002	†Jun 2003	†Jan–Jun 2002	†Jan–Jun 2003	% Change
Naphtha/LDF	111,416	199,990	543,977	1,187,092	118
ATF – Kerosene	832,652	845,090	4,759,835	4,923,928	3
Petrol	–	–	–	–	–
of which unleaded	1,562,653	1,534,001	9,811,254	9,443,193	–4
of which Super unleaded	43,345	72,666	259,759	404,083	56
ULSP (ultra low sulfur petrol)	1,519,308	1,461,335	9,551,495	9,039,110	–5
Lead Replacement Petrol (LRP)	52,014	19,702	293,536	116,401	–60
Burning Oil	177,093	500,386	2,008,739	2,121,118	6
Automotive Diesel	1,281,304	1,371,267	8,233,366	8,216,025	0
Gas/Diesel Oil	413,402	538,355	3,051,978	3,114,821	2
Fuel Oil	95,597	247,393	1,047,413	1,231,283	18
Lubricating Oil	65,633	69,147	419,680	420,947	0
Other Products	628,700	744,412	4,054,134	4,189,090	3
Total above	5,220,464	6,069,743	34,223,912	34,983,868	2
Refinery Consumption	374,326	399,746	2,442,115	2,288,022	–6
Total all products	5,594,790	6,469,489	36,666,027	37,271,890	2

† Revised with adjustments

All figures provided by the UK Department of Trade and Industry (DTI)

Straining to slow the production declines

Despite continuing discovery and the bringing forward of new projects, the North Sea is now a province in decline. *Chris Skrebowski* reports on prospects for a region that supplied 8.6% of the world's oil and 7.8% of the world's gas in 2002.

Of the five North Sea producers – Norway, the UK, Denmark, the Netherlands and Germany – only Denmark recorded a production increase in 2002 (see **Table1**). This pattern of expanding oil production in Denmark but slow declines in all other sectors continued in the first half of 2003. For gas production the picture is more positive, with Norwegian production expanding, Danish and Dutch production holding steady, and only UK gas production in clear decline (see **Table 2**).

Asset rationalisation

The last three years have seen oil prices holding above $25/b for Brent. This has undoubtedly increased investment interest in the North Sea despite it being a mature, high cost province. For the international oil companies – the majors and super majors – a lack of large projects and the progressive run down of existing production assets means that the North Sea is becoming less material to their operations. This is increasingly manifesting itself in a preparedness to sell assets, rationalise holdings and to sell or relinquish acreage. For example, Shell has started to sell and rationalise its North Sea holdings while BP has passed on what was once the jewel in its North Sea crown by selling the Forties field to Apache.

The process of asset rationalisation has only really got going in the last two years and is clearly a process that has some way to run. The last 12 months has seen sales and divestments by Amerada Hess, BP, Shell, ChevronTexaco, ConocoPhillips, Eni, Total and Murphy Petroleum. The new entrants and some of the smaller companies eager to squeeze the rocks a little harder have been the buyers.

	1998	1999	2000	2001	2002	2003*	2004*
Norway	3,139	3,139	3,346	3,418	3,330	3,262*	3,292*
UK	2,793	2,893	2,657	2,476	2,463	2,431*	2,358*
Denmark	235	301	364	347	371	377	414
Netherlands**	20	20	20	35	46	47	45
Germany**	22	22	21	21	20	20	19
Total	**6,209**	**6,375**	**6,408**	**6,297**	**6,230**	**6,137**	**6,128**

Source: BP Statistical Review June 2003 *except* * IEA Monthly report July 2003
** Petroleum Review *estimate*

Table 1: North Sea oil production (,000 b/d)

	1998	1999	2000	2001	2002
Norway	44.2	48.5	49.7	53.9	65.4
UK	90.2	99.1	108.3	105.8	103.1
Denmark	7.6	7.8	8.1	8.4	8.4
Netherlands	21.3	19.9	19.8	20.0	20.0
Total	**163.3**	**175.3**	**185.9**	**188.1**	**196.9**

Table 2: North Sea gas production (bn cm)

Notable amongst those acquiring assets on the UKCS in the last year have been ATP Oil & Gas, Centrica, Dana Petroleum, Paladin Resources, Encana, Energy Africa, Petro-Canada, Tullow Oil, Premier Oil, Talisman Energy, Edinburgh Oil and Gas, Canadian Natural Resources (CNR) and Venture Production (see p42).

The analyst Wood MacKenzie has assessed the impact of the newer entrants to the UKCS and tabulated their reserves holdings alongside those of the established players (see p30). It also notes the way that some of the new entrants have active exploration programmes rather than just focusing on lowering the cost of operating end of life assets. In sharp contrast to the large-scale divestments seen on the UKCS similar activity in the Dutch, Norwegian and Danish Sectors has, so far, been quite limited. However as decline sets in the same 'changing of the guard' being seen in the UK sector seems likely as the majors withdraw, leaving the field to the new entrants with their lower cost structure.

While the major companies have been selling and rationalising their field assets, so far there has been no sales of major pipelines and only a very limited rationalisation of holdings in some East Anglian gas reception terminals. At Bacton Perenco has taken on BP's non-operated southern North Sea Bacton assets making use of a new commercial and legal framework – known as the Master Deed – which has been designed by the DTI and Pilot to speed the transfer of North Sea assets and pave the way for new entrants. Perenco has acquired BP's operated Bacton assets and the Bacton terminal. It has now become operator for the fields and the terminal.

Major strategy

There seems to be three strands to the oil major's current strategy for the North Sea. Firstly, minimise costs by rationalising assets and selling fields once unit costs start to really rise. The latest UKOOA *Economic Report 2002* predicts unit operating costs to rise by 20% from the current $4.1/boe to $4.9/boe by 2010. Secondly, hang on to the main pipeline and terminal assets for as long as possible and try to load them up to keep unit costs down. And thirdly, but most important of all, postpone abandonment, with its attendant heavy costs for as long as possible.

The UKOOA report also notes that decommissioning costs in the UK sector have increased by £400mn from the 2001 survey to £8.8bn. The Association foresees expenditures rising steadily from 2005 and culminating in the

2025–2030 period. It does note, however, that there has been little decommissioning experience to date so costs are uncertain. An optimist would probably argue that practical experience of large-scale decommissioning would almost certainly drive down costs as skill and innovation are brought to play on the problem.

Discoveries and development

As would be expected in a mature province both the average size of discoveries and the average size of developments are declining. In the UKCS 2002 discovery was under 100mn boe, apparently justifying the low level of exploration and the moves to have single North Sea exploration units such as the one Shell recently announced. There are those who believe rather more aggressive exploration is warranted (see p20). Danish and Dutch sector exploration is also proving fairly unrewarding and even the Norwegians are now starting to worry (see p22). A particular concern for the Norwegians is the recent downward revision of their reserves (see p22 and box on p14).

For the moment all the main sectors feature quite active development programmes, even if much of the work is largely unseen as it comprises subsea completions and hook ups. In 2002 the largest developments (by reserves) in Norway were Norsk Hydro's Troll satellites and the first subsea production from ExxonMobil's Ringhorne field. This year has already seen the start-up of the main Ringhorne platform and the Valhall flanks development. Other key developments for this year are the start-up of the Valhall water injection platform, the Mikkel gas field and oil production from Fram West and the Vigdis extension. The largest oil reserves will, however, be accessed in October with the start-up of ExxonMobil's 700mn barrel Grane field.

In sharp contrast to the 1.3mn barrels of reserves being developed in Norway this year all other sectors have only fairly small additions. In the UK sector the two largest oil developments are Penguins and the latest expansion of Schiehallion – the Claw development. Each of these involves around 50mn barrels of reserves. Similar sized reserves were developed last year on the UKCS when Alba extreme south (50mn barrels), ETAP II (Madoes/Mirren 57mn barrels), Otter (45mn barrels), Magnus EOR (60mn barrels) and the Schiehallion North Channel (50mn barrels) were brought onstream.

In the Danish sector the key development has been the various phases of the Halfdan field, now recognised as the country's second largest field with reserves of 400–500mn barrels. The small Cecilie and Nini fields are due onstream this year, feeding through the Siri facilities. Looking forward there are virtually no new Danish developments of any substance to come, which is why the Danish Authorities are now predicting oil production declines of 10%/y after production peaks in 2004 (2005 for the optimists).

In terms of gas developments this year will see the start-up of Shell's Carrack field, Total's Nuggets N4 and BG's Juno project – all significant new producers. However, even with help from the 400bn cf CMS III and the 400bn cf Jade projects which started up in 2002, UK gas production is expected to decline leading to the country once again becoming a net gas importer. UKOOA has already brought forward its estimate of the import date to 2005 and it is now even possible that imports could begin at the end of 2004.

UK/Norwegian cooperation

The UK and Norwegian Governments have spent much of the year negotiating about facilitating developments in the strip around the median line and modifying landing obligations and cross border permitting so as to facilitate development of fields and imports of Norwegian gas into the UK.

A treaty is expected to be signed by the end of the year which could, according to UKOOA, open up the development of 10bn boe to 2010 and a further 5bn boe in the next decade, split roughly 50:50 between the two countries.

Looking ahead

Looking further ahead there are still a number of quite large developments to come on both sides of the median line. In the UKCS major oil developments to come include Clair South and Buzzard, while gas and condensate projects include Goldeneye, Rhum, and probably Devenick. In the Norwegian sector the ever-productive Ekofisk, Gjoa, Goliat and the Oseberg flank offer oil, while Snøhvit, Ormen Lange, Gudrun and Skarv offer gas or condensate.

While there are clearly great challenges ahead to slow the region's production decline there are clearly many eager to take up the challenge.

UKCS future outlook

The following highlights are taken from the recently published UKOOA *Economic Report 2002*.

- There are 260 oil and gas fields under development or in production on the UKCS compared to 248 in 2001.
- Remaining reserves in these developments are around 11bn boe, an increase of 1bn boe.
- There are 84 new field developments planned for the future (2001: 148).
- The survey identified 144 projects in mature fields (2001: 96). Total oil and gas production up to 2010 is forecast to be 12.9bn boe. This is some 370mn boe lower than predicted in 2001.
- Total capital expenditure up to 2010 is forecast to increase by around £1bn, compared to the estimated from last year's survey. In combination with the falling production estimates this indicates a disturbing trend of deteriorating financial performance.
- Capital development spend in 2002 is expected to meet 2001 forecasts of between £3.3bn and £3.8bn.
- Unit operating costs are forecast to rise by 20% – from $4.1/boe to $4.9/boe by 2010.
- The Pilot production objective of 3mn boe/d for 2010 is becoming more difficult to achieve.
- UKCS reserves at the beginning of 2002 were estimated to be between 24–32bn boe. This compares with some 31bn boe already produced. About half of these reserves are yet to be produced.
- Oil and gas production in 2002 declined slightly to 4.2mn boe/d, with a value of £21bn, or some 2.4% of gross added value.
- The industry has supported over 265,000 jobs across the UK.
- Wood Mackenzie ranked the attractiveness of UKCS exploration 31st out of 57 areas in the world.
- Some $5.1bn in assets changed ownership in 2002.
- Treasury receipts from the industry amounted to some £4.9bn, the total tax contributions from the industry amounting to £190bn since North Sea activity began in the mid-1960s.

Norway reduces hydrocarbons potential

Norway has reduced its oil and gas reserves by almost 8%, according to a new report updated to the end of May 2003, writes *Brian Warshaw*. The Norwegian Petroleum Directorate (NPD) calculates that there are 12.8bn cmoe remaining for recovery, 1bn less than forecast at the end of 2002. While 40% of these recoverable reserves remain to be discovered, most of this reduction has been accounted for by downsizing the potential for gas production.

Viewing the Norwegian Continental Shelf as three provinces, the North Sea, the Norwegian Sea and the Barents Sea, the NPD has reduced the potential for the North Sea by 30%, based on the greater knowledge of the geology that has been acquired for this area. Expectations have also been reduced for the deeper parts of the Vøring Basin, but recent mapping has raised forecasts for the areas off Loften.

Calling for greater recovery in producing fields, the NPD says that 55% of oil currently stays in the field; it continues to hope for a 50% recovery rate in oil fields and 75% in gas fields. It recognises that this may be difficult due to profitability and lack of technological developments.

Recognising that the easiest fields have been developed in the past 32 years, the NPD predicts that it will be difficult to realise these reserves if the present low exploration activity continues. It also sees a lack of pipeline infrastructure as restricting gas production; with many discoveries awaiting access to existing pipelines, there will be no capacity for additional volumes until after 2020.

Commenting on the report, Statoil's Kent Høgseth, head of Deepwater Exploration, agreed that it was right for the NPD to lower the estimates after a series of dry wells in recent years, but predicted that large discoveries would be made in the Norwegian and Barents Seas.

Denmark	
Gorm	80%
Dan	56%
Skjold	76%
Halfdan	10.5%
Norway	
Ekofisk	62%
Gullfaks (main)	85%
Oseberg (main)	84%
Statfjord	89%
Troll	30%
UK	
Forties	95%
Ninian	95%
Piper	92%
Cormorant	85%
Brent	78%
Claymore	80%
Beryl	78%
Magnus	73.6%
Schiehallion	19%

Table 3: Percentage depletion of North Sea giant fields at end 2002

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
Onstream 2002								
Alba extreme south	oil	16/26	ChevronTexaco	Oct-02	15mn b or 50mn boe		14 subsea wells to Alba plat.	50,000 b/d
Bains	gas	110/03b	Centrica	Nov-02		45bn cf	tieback to Morecambe S	35mn cf/d (03)
Brigantine C	gas	49/19	Shell	Jul-02	1mn boe	or 6bn cf	via Corvette	
Boyle	gas	49/30a	BP	Oct-02	9mn boe			
CMS III	gas	44/22a	ConocoPhillips	Sep-02	68mn boe	430bn cf	Tiebacks to Murdock plat.	300mn cf/d (04)
Douglas West	oil	110/13b	BHP Billiton	2002	6mn boe			
ETAP II (Madoes/Mirren)	oil	22/23b,28a,28c, 22/25b	BP	Nov/Dec-02	57mn boe	50bn cf	5 wells to Marnock	32,000 b/d(2003), 30mn cf/d (04)
Halley	oil/gas	30/12b	Talisman	Jul-02	7–9mn b	9bn cf	2 ER wells from Fulmar	11,000 b/d (2002), 13mn cf/d (02)
Hannay	oil	20/5c	Talisman	Mar-02	10mn b		2 well tieback to Buchan ss	7,000 b/d (02)
Jade	gas/cond	30/2c	ConocoPhillips	Feb-02	15–30mn b (cond)	400bn cf	steel plat. via Judy/CATs	20,000 b/d (02), 200mn cf/d
Lewis	oil	9/13a	ExxonMobil	Apr-02			tieback to Beryl Alpha	6,000 b/d (02)
Magnus EOR	oil	211/12a	BP	Nov-02	additnl 60mn b	200bn cf	infill wells, misc gas injec	38,000 b/d to 49,000 b/d
Maclure	oil/gas	9/19 Area N	BP	Jul-02	12–19mn b	65bn cf	1 subsea to Gryphon FPSO	15-19,000 b/d (02), 20mn cf/d (06)
Otter (Wendy)	oil	210/15a	Total	Oct-02	30–45mn b		3 prod, 2 inj to Eider plat.	30,000 b/d (03)
Schiehallion Ph III	oil	204/20, 204/25	BP	May-02	N. Channel 100mn b	or 163mn boe	3 prodn+ 5 inject to FPSO	
Skua	oil/gas	22/24b	Shell	Oct-02	21–25mn b	24bn cf	2 subsea wells to Marnock	19-24,000 b/d (02), 15mn cf/d (03)
Tullich (Ph I)	oil/gas	9/23a	Kerr-McGee	Sep-02	22mn boe		4 subsea to Gryphon FPSO	15,000 b/d (03), 6mn cf/d
Viscount/Vanguard extn	gas	49/16	ConocoPhillips	Nov-02		150bn cf 3	horiz subsea via Loggs	90mn cf/d
Onstream 2003								
Amy and Argo area	gas	48/10b,48/9a	ConocoPhillips	2003		370bn cf	plat.	
Ardmore (Argyll redev)	oil	30/24	Tuscan Energy	late 2003	20–25mn b		4 highly deviated from JU	40,000 b/d (04)
Atlantic & Cromarty	gas/cond	13/30b, 14/26	Amerada Hess	2003	3mn b (cond)	250bn cf	tieback to Goldeneye?	
Beechnut	oil/gas	29/9b	Amerada Hess	2003			subsea tieback or FPSO	20,000 b/d
Blake flank	oil	13/24a, 24b, 29b	BG	3Q2003	20mn b		2 wells tied back	
Braemar	gas/cond	16/3c	Marathon	4Q–03	9–10mn b (cond)	107-115bn cf	1 subsea well to Brae B	4,000 b/d (03), 46 mn cf/d (03)
Calder	gas	110/7a	Burlington	4Q–03	49,000 b (cond)	350-400bn cf	NNM plat.	80mn cf/d)
Caledonia (Parlmnt)	oil	16/26	ChevronTexaco	Feb-03	10.3mn b	or 15mn boe	subsea to Britannia	10,000 b/d (04)
Carrack (Cleaver Bank)	gas	49/14b	Shell	late 2003	6mn b (cond)	300bn cf	plat., subsea to Clipper (85km)	4,000 b/d, 196mn cf/d
Don redev. W,SE (SA)	oil	211/18a	BP 2003		35mn b	subsea tieback to Don		
Helvellyn	gas	47/10b	ATP Oil & Gas(UK)	2003		50bn cf	subsea to Amethyst plat.	36mn cf/d (for 5 years)
Howe	oil	22/12a	Shell	end 2003	15mn b	5bn cf	subsea tieback to Nelson	
Harding area gas	gas	9/23b	BP	end 2003			appraisal tiebacks to Harding plat.	
Jade NE Flank	gas/cond	30/2c	ConocoPhillips	2003	30mn boe (cond)		2 wells tied back	10-20,000 b/d (04)
Juno project (ECA2)	gas	47/3b, 3c, 4a, 4b	BG	Jan-03		300bn cf	subsea + Minerva plat.	300mn cf/d(2003)or 8.5mn cm/d
Nuggets Ph II (N4)	gas	3/18c, 19a, 19b, 20a, 24a,	Total	4Q2003		500bn cf	subsea	45mn cf/d (04)
Penguin A,C,D,E	hvy oil	211/13, 211/14	Shell	Jan-03	50mn b	175bn cf	subsea to Brent C (65km)	40,000 b/d (03), 70mn cf/d (03)
Jill & Julia (SA)	oil/gas	30/7a	ConocoPhillips	2003			subsea tieback	

Table 1: North Sea fields onstream in 2003 and beyond

continued overleaf...

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
Schiehallion Ph 4 (Claw)	oil	204/20, 204/25	BP	2003	50mn b?		3 prodn+ 5 inject to FPSO	
Scoter	gas/cond	22/30a	Shell	end–03	3mn b or 40mn boe	180bn cf	tieback to Shearwater	6,000 b/d (03)
Seymour	oil/gas	22/05b	BG	Mar-03			subsea tieback to Armada	
Sycamore (Pine, N, Elm)	oil	16/7, 16/12a	Venture Petroleum	Mar-03	24mn boe	14bn cf	2 subsea to Brae A	27,000 b/d (04), 30.5mn cf/d (04)
Sycamore Ph II,III	oil	16/7, 16/12a	Venture Petroleum	2H2003	24mn boe	14bn cf	5-7 subsea to Brae A	27,000 b/d (04), 30.5mn cf/d (04)
Skene Ph2 (Brora)	gas/cond	9/19	ExxonMobil					
South West Seymour	gas	22/5b	BP	2Q2003			tieback to Armada	
Venture	gas	49/12a	ConocoPhillips	2003		50bn cf	tieback	
Onstream 2004								
Blane	oil	30/3a	Shell	2004	15–40mn b		Subsea tieback to Pierce	15-25,000 b/d, 6-10mn cf/d (Ph1)
Broom (ex W Heather)	oil	2/5	DNO	2004	22mn b		3prodn,2 inj t/bk to Heather	10,000 b/d (04)
Bruce (upgrade)			BP	2004			additional compression	
Cavendish Area	gas	43/19a	RWE-DEA	2004		138bn cf	subsea to Trent	51mn cf/d (04)
Chiswick	gas	49/3a	Centrica	2004		120bn cf	plat.	
Chestnut Ph II	oil	22/2a	Amerada Hess	2004	15–20mn b		FPSO	18,000 b/d
Clair South	oil	206/7a, 8, 9a, 12, 13a	BP	2004	273mn b or 267mn boe		1 or 2 fixed steel plat.s	80,000 b/d (05)
Clapham	oil	21/24	Petro-Canada	2004	19.5mn b		subsea to Guillemot NW	15,000 b/d (04)
Curlew A–D	oil	29/7	Shell	2003	20mn boe		subsea to Curlew	
Fiddich (ETAP III)	gas/oil	CNS	BP	late 04	5mn b (cond)	100bn cf	2 well tieback to Marnock	2,000 b/d cond (06), 40mn cf/d (05/6)
Goosander	oil	21/12, 21/13a	Shell	2004	16mn b++		subsea to Kittiwake	15,000 b/d
Goldeneye	gas/cond	14/29a, 20/4b	Shell	Oct-04	17mn b (cond)	500 or 655bn cf	NNM plat., 105km t/b St Ferg	30,000 b/d (05), 234mn cf/d (05)
Magnus NW	oil	211/7a	BP	2004	10mn b		ERD	
Orca and Minkie	gas	44/24a, 29b, 30	Gaz de France	2004		342bn cf	wellh'd plat. to D/15-FA	72mn cf/d (05)
Perth	oil/gas	15/21b	Amerada Hess	2004	33mn b	28bn cf	subsea to Scott	20,000 b/d (05)
Rivers Calder/Hod/Crosns	gas	110/7a	Burlington	2004	49,000 b (cond)	350-400bn cf	to NNM plat. on Calder	80mn cf/d (2006)
Rhum Ph I	gas/cond	3/29a	BP 3Q	2004	5mn b (cond)	800bn cf	3 subsea T'bk 44km to Bruce	
Rose	gas	47/15b	Centrica	2004		88bn cf		
Topaz	gas	SGB	RWE-DEA	2004		50bn cf		
Onstream 2005								
Devenick	oil	9/24b	BP	2005	123mn boe	480bn cf	plat. or tieback to Harding	
Ettrick	oil	20/2a	Shell	2005	35mn b		FPSO or subsea	
Enoch/J1	oil/cond	16/13a	Shell	2005	10.4mn b	67bn cf	subsea to Miller or Brae	10,000 b/d (03), 15mn cf/d (03)
Glenelg	Oil/gas	29/4d	Total	2005	40mn b (cond)	200bn cf	wellhead plat. via Elgin PUQ	
Jacqui	oil/gas	30/13	ConocoPhillips	2005	10mn b	70bn cf	subsea to Judy	10,000 b/d (05), 50mn cf/d (05)
Rhum (Ph II)	gas/cond	3/29a	BP	2005	5mn b (cond)	800bn cf	6 subsea T'bk 44km to Bruce	
Onstream 2006								
Alder	gas/cond	15/29a	ChevronTexaco	2006	30mn b (liquids)	250bn cf	subsea tieback	
Brodgar & Callanish	gas/oil		ConocoPhillips	2006	40mn b + 20mn b (cond)	175bn cf	subsea tieback	
Buzzard	oil	20/6	EnCana	2006	500mn b		Two plat.s	
Kessog (SA)	gas/cond	30/01c	BP	2006	60mn b (cond)	260bn cf	unmanned plat. or subsea	
Macallan	gas/cond	CNS	ConocoPhillips	2006	5mn b (cond)	50bn cf	subsea tieback	
Puffin	oil/gas	29/4a, 5a, 9a, 10	Shell	2006	25mn b + 40mn b (cond)	260bn cf	wellh'd plat. to Shearwater	18,000 b/d (08), 150mn cf/d (08)
Onstream 2007								
Rivers2 Crossans/Darwen	gas	110/2b, 110/7a	Burlington	2007		120bn cf		
Possible dev's								
Alwyn North Trias			Total					
Anglia	gas							
Ani			Shell				subsea tieback	
Appleton area	gas/cond	30/11	Talisman		40mn b	60bn cf		
Arbroath/Montrose	oil	22/17, 18	BP				Poss comp plat.	
Auk North	oil	30/16	Shell		25–30mn b		subsea to Auk	
Babbage	gas	48/2a	TXU		165bn cf		subsea to Johnston	
Bedevere	gas	48/14	ExxonMobil			100bn cf	ERD	40mn cf/d (04)
Bennachie	oil	21/15a, 15b	Shell 15mn b				subsea to Forties or Nelson	10,000 b/d
Beta (UK)	gas	44/24a	Consort Resources			75bn cf	wellh'd plat. to Orca	35mn cf/d (03)
Block 15/23	cond	15/23d	BG					
Block 16/26	oil	16/26a	BP plat.					
Blythe	gas		BP					
Bressay	hvy oil	3/28a	ChevronTexaco		200mn b			
Brigitte	gas		BG					
Dolphin		22/18	BP					
Ensign	gas	48/14	Centrica plat.					
Flyndre			Total				subsea tieback	
Fyne/Dandy	oil	21/28a	Lasmo		39mn b		FPSO?	
Gadwall	oil/gas	21/19	Shell		9mn b	7bn cf	subsea to Kittiwake	10,000 b/d (02), 7mn cf/d (02)
Glenn			BP				subsea tieback	
Hunter	gas	44/23a	Total				subsea tieback	
Inde NE	gas	49/19	Shell			45bn cf	subsea tieback	50mn cf/d (02)
Johnston Gamma			BHP				ERW	
Josephine	oil/gas	30/13	ConocoPhillips		30mn boe	95bn cf	subsea to Judy	8,000 b/d (03), 50mn cf/d (03)
Kate/Turnstone	oil/gas	22/23b, 28a	BP?		73mn boe	20bn cf	subsea	20,000 b/d (02), 15mn cf/d (01)
Kildrummy (Lucy)	oil	15/12b, 15/17	Talisman		40mn b	25mn boe	subsea tieback to Piper B	

Table 1: North Sea fields onstream in 2003 and beyond

continued overleaf...

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
Lennox			West Burlington				subsea	
Mandarin	oil	22/23b, 22/28d, 22/28a	Shell					
Marcel/Bravo								
Mariner	hvy oil	9/11a	ChevronTexaco		100mn b		project on hold	
Melville		210/24b	Amerada Hess				subsea	
Mirren	oil/gas	22/25b	Shell				subsea	
Nevis Central			ExxonMobil				subsea	
Nevis Far North			ExxonMobil ERW					
Peik UK	oil/gas	9/15a	Total		20mn b	350bn cf	subsea to Beryl A	9,000 b/d (03), 110mn cf/d
Pilot	oil	21/27	Total		77mn b		floater?	
R Block	oil	15/27	ConocoPhillips					
Ramsay	gas	53/5b	BP			75bn cf	ERW from Davy?	
Skye	oil	211/23a, 23c	Shell		20mn b		subsea to Dunlin	11,000 b/d
Solan/Str'thm're (SA)	oil/gas	204/30	Amerada Hess FPSO					40,000 b/d
Suilven	oil	204/19	BP					
Thebe	gas	49/22	ConocoPhillips			74bn cf	with ECA Phase II	35mn cf/d
Tornedo	oil	22/23b, 28a, 28c	Shell		30mn b			20,000 b/d
Wissey	gas	53/04	BP subsea					
Wood (SA)	oil/gas	22/18	Nisus consort'/BP		15mn boe		1-2 subsea to Arbroath	
York	gas	47/3a	Amerada Hess		test 24.7mn cf/d	200bn cf		
Key Discoveries								
Rochelle	oil/gas	15/27-9	Amerada Hess		7,973 b/d on test	4.67mn cf/d on test		
Lucy	oil	15/12b, 15/17	Talisman		22mn b	10bn cf	tieback to Piper	
K field	gas	44/22a, 44/23a	ConocoPhilliips	4Q2002		80bn cf	Caister Murdock (CMS III)	
York	gas	47/3a	Amerada Hess	2003?	test 24.7mn cf/d	200bn cf	Incorp in ECA2?	
Buzzard	oil	20/6	PanCanadian		200–300mn b		plat.?	
Forvie North	gas/cond	3/15	Total		test 1mn cm/d,1.4kb/d cond			
Barbara	gas/cond	23/16c-8	Dana Petroleum					
close to Buchan	oil/gas	21/1a-19	Talisman		40–70mn b		in place	
close to Brigantine	gas	49/20a, 49/20b	Shell					
West Franklin	gas/cond	29/5b	Total test		1mn cm/d,2kb/d cnd			
close to Buzzard	oil	20/6	Edinburgh Oil&Gas		30mn b			
NETHERLANDS								
2002 and after								
A & B quadrant	gas	A12A	NAM	2005		400bn cf	plat.	
F16-A	gas	F16/E18	Wintershall	2005			process plat. + sat plat.	
G16-FA	gas	G16	NAM	2005		220bn cf	plat.	
K/1A	gas	J/3A, K/1A	Total	Mar-02		520bn cf	plat.	83mn cf/d (03)
K/2-FA	gas	K/2	NAM	2005		250bn cf	plat.	
K4b/5a	gas	K5a	Total	2003				plat.
K7-FB	gas	K7	NAM	2003			plat. to K7-FD-1	
K12	gas	K12	Gaz de France	2002		50bn cf S2	subsea to K12-1	
K12	gas	K12	Gaz de France	2003		S3 subsea to	12-1	
K15-FK	gas	K15	NAM	2003			plat. to K15-FB-1	
L4-G	gas	L4	Total	2005		100bn cf	plat.	
L5-B	gas	L5	Wintershall	2003			plat. to L8-P4	
Q1-B	gas	Q/1,Q/4	Wintershall	2003		400bn cf	plat. t/b to Hoorn	34mn cf/d
Q4-B	gas	Q4	Wintershall	2002			plat. to Q4-A	
Q5-A	gas	Q5	Wintershall	2004		21bn cf	subsea to Q8-B	
Probable dev's								
K/5-Fe	gas	K/5	Total	2002		80bn cf	plat.	
K/7-FB	gas	K/7	NAM	2003		150bn cf	plat.	
K/15-FE	gas	K/15	NAM	2003		30bn cf	plat.	
K15-FJ	gas	K/15	NAM	2004		40bn cf	plat.	
L/2-FB	gas	L/2	NAM	2003		85bn cf	plat.	
L/9-6	gas	L/9A, L/9B	NAM	2003		100bn cf	plat.	
Minke (Neth)	gas	M/7	NAM	2003		100bn cf	plat.	45mn cf/d
Orca (Neth)	gas	D/15, D/18A	NAM	2003		104bn cf	plat.	40mn cf/d
Q/1-A	gas	Q/1	Conoco	2004		400bn cf		
Key Discoveries								
K15	gas	K/15	Shell, ExxonMobil			300bn cf		
NORWAY								
Onstream 2002								
Rogn South	oil	6407/9	Norske Shell	2002	35mn b		subsea to Draugen	
Sigyn	oil/gas	16/7	ExxonMobil	2002	35mn b (cond)	200bn cf	subsea to Sleipner A	
Troll III (satellites)	oil block	31/2	Norsk Hydro	Jun-02	105mn b		subsea t'bk to Troll B and C	
Trym	gas/cond	3/7, 8	Shell	2002	5mn b 3.3bn cm		subsea to Harald (Denmark)	
Tune A (ex Draken)	gas/cond	30/8,30/ 5, 30/6	Norsk Hydro	Nov-02	44mn b 27bn cm		subsea to Oseberg D	10mn cm/d, 25,000 b/d (cond)
Vale	gas/cnd	25/4	Norsk Hydro	May-02	21mn b (cond)	2.5bn cm	subsea to Heimdal riser plat.	1,600 cm/d
Visund North	oil Block	34/8	Norsk Hydro	Feb-02	19mn b		tieback to Visund plat.	40,000 b/d (03)

Table 1: North Sea fields onstream in 2003 and beyond

continued overleaf...

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
Onstream 2003								
Byggve	gas/cond	25/5	Total	Aug-03	4.4mn b (cond)	2.4bn cm	subsea to Heimdal	
Fram West (incl Sogn)	oil/gas	35/11,31/2	Norsk Hydro	Oct-03	100mn b	3.5bn cm	subsea via Troll C	60,000 b/d
Glitne II	oil Block	15/5, 15/6	Statoil	2003	10mn b		subsea to Glitne FPSO	
Grane (Hermod)	oil block	25/11	Norsk Hydro	Oct-03	705mn b (hvy oil)	1.8bn cm	PDQ plat. over	215,000 b/d (05-09)
*Mikkel	gas/cond	6407/6, 6407/5	Statoil	4Q03	35mn b (cond)	22bn cm	4 subsea to Asgard B	30,000 b/d
Ringhorne II (plat.)	oil block	25/10,11, 25/8	ExxonMobil	Feb-03	280mn b	2bn cm	PDQ plat. via Balder	80,000 b/d, 28mn cf/d
Valhall Flanks	oil Block	2/8, 2/11	BP	May-03	additional 110mn b		2 wellhead plat.s	
Valhall water inject	oil block	2/8, 2/11	BP	2003	additional 150mn b 15		well plat. to inj 210,000	60,000 b/d
Varg South	oil/gas	15/12	Pertra PGS	2003	40mn b	4bn cm	ERD well from Varg	
Vigdis Extension	oil block	34/7	Norsk Hydro	2003	50mn b		subsea to Snorre	
Onstream 2004								
Kvitebjorn	gas/cond	34/11	Statoil	Oct-04	135mn b (cond)	52bn cm	PDQ plat. (Aker to build)	20mn cm/d
Oseberg J South	oil/gas		Norsk Hydro	Oct-04	24mn b	0.5bn cm	subsea to Oseberg South	21,000 b/d
Sleipner Alpha North	gas/cond	15/6	Statoil	2004	32mn b (cond)	13bn cm	subsea to Sleipner T	
Onstream 2005+								
Dagny	gas/cond	15/6, 15/5	Statoil	2008	6.3mn b cond	5.8bn cm	subsea via Sleipner A	
Ekofisk Growth	oil/gas	2/4	Phillips	2005	156mn boe		wellhead plat. +mods	
Falk	oil	6608/11	Statoil	2007	6.3mn b		subsea to Norne	
Freja-Mjolner	oil	2/12	Amerada Hess	2007	18.2mn b	0.6bn cm	subsea to Valhall or Arne	
Gjoa	oil/gas	35/9, 36/7	Norsk Hydro	mid 2006	41mn b	29.4bn cm	subsea to Troll	
Goliat	oil	7122/7 (Barents Sea)	Agip	2006	50mn b		FPSO	
Gudrun	gas/cond	15/2, 15/3	Statoil	2006	87mn b (cond)	15.6bn cm	NNM plat. to Sleipner/Brae	
Heimdal West	oil/gas	24/6, 25/4	Marathon	2006			FPSO or tiebk Heimdal	
Idun (ex Fangst)	gas	6507/3	Statoil	2008	4mn b	17.4bn cm	subsea to Skarv?	
Kristin	gas/cond	6406/2-3, 11	Statoil	Oct-05	220mn b cond	35.4bn cm	12 subsea to FPU toAasgard	126,000 b/d (cond), 18mn cm/d
Lavrans	gas/cond	6406/2	Statoil	2008	30mn b	13,4bn cm	subsea to Kristin	
Lerke	oil	6608/10	Statoil	2005			subsea to Norne	
Njord Gas	gas	6407/7,10	Norsk Hydro	2005	10bn cm		mdifications	
Ole/Dole/Dolly	oil	33/12	Statoil	2005	13.2mn b	1.1bn cm	subsea Statfjord/Oseberg	
Ormen Lange	gas/cond	6305/4,5,7,8	Norsk Hydro	2007	138mn b (cond)	375bn cm	processing plat.	50mn cm/d, 20 year plat.eau
Oseberg Delta	gas/cond	30/9, 30/8	Norsk Hydro	2005	7mn b	4bn cm	subsea/ERD via Oseberg	
Oseberg West Flank	oil/gas	30/6	Norsk Hydro	2005	190mn b	6bn cm	subsea via Oseberg	
Skarv	gas/cond	6507/3,5,6	BP	2008	65–140mn b	31-67bn cm	FPSO or tieback to Heidrun	11.3mn cm/d
Snoehvit+ others	gas/cond	7120/5,6,7,8,9, 7121/4,5,7	Statoil	2006	114mn b (cond)	164bn cm	subsea 160km to Melkoya	20.8mn cm/d
Staer	oil	6608/10	Statoil	2005	30mn b	0.3bn cm	subsea to Norne	
Svale	oil	6608/10	Statoil	2005	50mn b		subsea via Norne	
Tommeliten Alpha	oil/gas	1/9	Phillips	2005	16mn b	3bn cm	subsea to Ekofisk?	
Troll A compression	gas	31/6	Statoil	2005			addiional compression	
Trym	gas/cond	3/7,3/8	Norske Shell	2007	5mn b (cond)	3.3bn cm	subsea to Arne South	
Tyrihans N &S	cond/gas	6407/1, 6406/3	Statoil	2007	122mn b (cond)	23bn cm	subsea to Asgard or Kristin	
Valhall Redevelopment	oil/gas	2/8, 2/11	BP	2007			process/accom plat.	150,000 b/d
Varg South	oil/gas	15/12	Pertra (PGS)	2005	25–30mn b	4bn cm	ERD from Varg + subs	
Visund Gas	gas	34/8	Norsk Hydro	2005	4.7mn t NGLs	55.5bn cm via	Visund F wells	
Volve	oil/gas	15/9	Statoil	2005	35mn b	1bn cm	FPSO	40,000 b/d
Key Discoveries								
President	oil/gas		Shell					1bn b? 1bn cm?
Kneler	oil	25/4	Marathon Oil				West Heimdal Area	
DENMARK								
2002 and after								
Adda	oil/gas	5504/8	Maersk	2005	6mn b	1bn cm	subsea or NNM to Tyra	
Alma	oil/gas	5505/17	Maersk	2007	6mn b	1bn cm	plat. to Dan F	4,000 b/d (04), 22mn cf/d (04)
Amalie	gas/cond	5604/26	DONG	2007	13mn b cond	3bn cm	plat. to South Arne	7,000 b/d (02), 42mn cf/d (06)
Boje	oil	5504/7	Maersk	2005	5mn b		subsea to Roar/Valdemar	
Cecilie/Nini	oil	5604-20, 5605-10	DONG	2003	65mn b		2 wellhead plats. via Siri	
Elly	oil/gas	5504/6a	Maersk	2007	6mn b	1bn cm	NNM plat. to Tyra	
Freja-Gert	oil	5603/27, 28	Maersk		7mn b	7bn cf	subsea	
Halfdan III	oil/gas	5505/13	Maersk	2003	486mn b	8.6bn cm	Two jackets + bridge	100,000 b/d
Halfdan North-East (Igor/Sif)	oil/gas	5505/13	Maersk	2003	7mn b	15bn cm	plat. to Dan F, Tyra	
Hejre	oil	5603/28	ConocoPhillips	2007			plat to South Arne	
Siri East Segment	oil	5605/13	DONG	2003	15mn b		subsea to Siri	
Tyra SE	oil/gas	5504/12	Maersk	Mar-02	6mn b	6bn cm	plat. toTyra East	
Key Discoveries								
Sofie-1	oil	20km northeast of Siri	Paladin	2004			tieback to Siri	
IRELAND								
Corrib	gas	18/20, 18/25	Shell	2004		850bn cf	subsea to shore	
Greensand	gas	48/25	Marathon	2003			subsea to Kinsale B	
Seven Heads	gas	48/22, 48/23	Ramco	end 2003		300bn cf 6	subsea to Kinsale A	
Key Discoveries								
Dooish	oil/gas	12/2-1	Shell	2010	up to 400mn boe			

Table 1: North Sea fields onstream in 2003 and beyond

Exploration beyond 2003 on the UKCS

John R V Brooks **CBE, Director of Brookwood Petroleum Advisors and formerly Director of the DTI's Consents and Exploration Branch, presents a personal view of the current status of exploration on the UKCS and what is required to stimulate further activity.**

Since 1998 there has been a significant fall in the number of exploration wells drilled each year on the United Kingdom Continental Shelf (UKCS) – from nearly 50 in 1998 to less than 30 wells per year; reducing to 16 in 1999, 26 in 2000, 24 in 2001, and returning to 16 in 2002. (See **Figure 1**.)

However, signs of improvement may be seen, with some ten exploration wells spudded in 1Q2003.

Reasons for decline

The reasons for the decline are probably varied. The first may be a function of the number of commitment wells offered during recent rounds of licensing, due to the nature of the acreage applied for and the play concepts perceived. There is also a perception that the North Sea area, even the UKCS as a whole, is a 'mature' region, thus justifying little exploration attention from oil companies. Many companies, however, are interested in prolonging the life of existing fields and are active in bringing forward existing discoveries to development. But unless further exploration wells are drilled and more hydrocarbons found, these existing reserves will soon be depleted.

An additional factor is the widely held view that all of the oil and gas, which may be easily identified and drilled for, has been found. It follows, therefore, that any remaining reserves will be present in more subtle traps, harder to image and identify, and in smaller accumulations – all of which leads to the conclusion that the risks involved in exploring are higher than hitherto thought and that the chances of finding hydrocarbons will be concomitantly less. The logic runs that continuing exploration will result in fewer and smaller discoveries, which may not be economic enough to bring to production.

As the remaining traps within a single play are drilled it is true that the discoveries tend to be smaller, simply because the larger structures tend to be drilled first in any basin. But even for current exploration targets the ratio of successful wells drilled to those that aren't remains encouragingly high.

Another reason may be found in the view, widely held in industry, that the UK Chancellor's Budget changes in 2002 did not assist investment in the UKCS.

One might assert that current licensees have not targeted any new exploration plays outside of the main play fairways for some years. Whilst seismic acquisition has been able to resolve new prospects within identified play fairways, and particularly those adjacent to producing fields, there has been no structured effort to search for, let alone conceive, new plays within the stratigraphic column in each of the basins within the UKCS.

Notwithstanding, companies recently new to the UK have been small and extremely focused on maximising extraction from existing fields and developing adjacent finds and other discoveries. Recent larger entrants have yet to show interest in new exploration, their prime reason for entering being to acquire major field assets and to extend field life beyond that which previous owners might have attained economically. Their track record elsewhere in the world might suggest that in time they will be keen to explore innovatively on the UKCS, and thus for all of these reasons their presence on the UKCS will be a stimulus to others and very welcome by UK plc.

A final factor contributing to a disinclination to drill new exploration wells is the reluctance of licensees (oil companies) to take on what are perceived to be high risk projects – that is to say *exploration wells* drilled to targets which are unproven and perhaps deeper (and therefore more costly) than those previously drilled. Comparison of risk between different offshore areas is now also a consideration put forward by international oil companies to affect the order in which wells are drilled, and which ones are drilled. Host governments usually attempt to break any such linkage and insist that commitment wells are drilled to a schedule on their territory.

So, the whole oil and gas exploration scene at the moment does not lend itself, from a licensee's perspective, to making an effort to search for more oil and gas out-

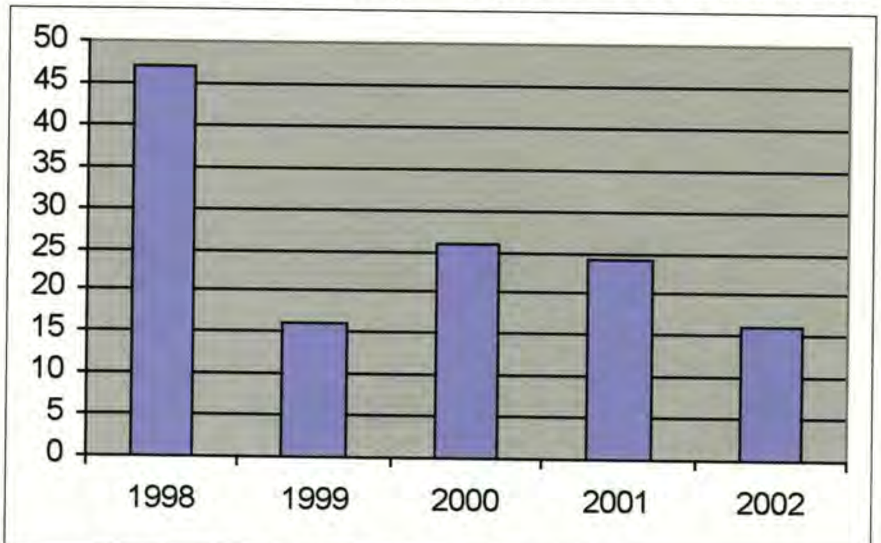


Figure 1: Annual number of offshore exploration wells in last five years

side of the established and known plays. Exploration (*sensu stricto*) on the UKCS at present is effectively non-existent.

Security of supply issues

The other perception is that renewable forms of energy may replace any shortfall in fossil fuels, and may even replace them altogether – a view not subscribed to by many alternative energy professionals. In the short term, save perhaps by use of hydrogen, it is not possible to fuel vehicles or aeroplanes without the use of fossil fuels. So, whilst alternatives may assist in the production of electricity, currently their deployment is useful but limited.

Set this view against the fact that indigenous reserves of both oil and gas are declining and that the UK will become a net importer of both from 2005–2010, and one begins to become concerned that few are raising the issue.

It may be that one of the options is to allow 'market forces' to determine an outcome. The logic runs that it is better to import currently cheaper sources of oil and gas, LNG for example, and explore deeper in the southern gas basin, develop coal bed methane or even clathrates when the need becomes really pressing.

Perhaps with uncertainty being quite unquantifiable in terms of resource evaluation, this may not be such a good idea. Building upon current geological knowledge whilst exploration and development are ongoing on the UKCS, even adjacent shelves, would seem to be a more reliable and prudent way to proceed.

The analogy with the US is not irrelevant (see *Petroleum Review*, August 2003), where the government has stopped exploration and development of oil and gas in areas where resources not only are thought to exist but have been proven to exist, and adjacent to states which utilise a great deal of resources, such as California and Florida. It is probably cheaper to import than to develop in the US at the present time, but with prices rising, particularly for gas, serious thought about the future will need to be taken. Indeed, this is already happening.

Stimulating exploration drilling

This situation does not assist the UK in prolonging self-sufficiency in either oil or gas. The fact remains that unless exploration is re-stimulated there is a very real danger that large resources of oil and gas will remain underground to the detriment of the UK. Just as in the 1960s eminent people said they would drink all of the oil found on the newly designated UKCS, so today it is the height of arrogance even to suggest that no oil or gas exists in traps which as yet have not even be looked for.

So, what actions may be taken to encourage exploration on the UKCS to ensure that all conceivable play concepts are identified evaluated and tested?

Promote licences

By announcing a 'Promote' Round (**www.og.dti.gov.uk/UKpromote/**) within the 21st Offshore Round of Licensing, the Licensing, Exploration and Development Branch in the Department of Trade & Industry (DTI) has gone some way to encourage petroleum geologists to come up with geological concepts that could lead to drilling unevaluated prospects.

Successful applicants for a Promote licence, which may embrace a number of contiguous blocks, will have two years to substantiate their ideas with seismic and well data and to acquire new seismic information. Before the end of this time, prospects must be 'promoted' for funding to drill.

New concepts know no block boundaries. So, whilst a new play may exist on an unlicensed block it may extend to adjacent licensed territory on which the optimum location to evaluate it may also exist. Some onus then clearly needs to be placed upon existing production licence holders, as well as those receiving production licences in the 21st Round, both to afford access to 'Promote' licensees and even to contribute to any evaluation.

The announcement at the end of July of the results of the 21st Round show 90 blocks and part-blocks being awarded to 53 applicants. This outcome must be seen as justification for the offering of such a licence in the first instance and it will be interesting to learn what new play concepts are being examined. All awards are shown to have work programmes of seismic data acquisition, usually 3D surveys with some 2D and some re-processing, and virtually all with 'drill or drop' options – ie a commitment to drill a well or relinquish the acreage at the discretion of the licensee.

Decisions on drilling will need to be made in two years, and thus a real measure of success of the take-up of the licences will be the number of firm wells committed and drilled as a result of the work programmes, and their exploration success in making discoveries of oil or gas. The identification of new plays will clearly be a factor in establishing future resources.

By contrast, of the 51 blocks awarded by a traditional 'production' licence, only a single firm well was offered.

Promote project funding

Funding may come from a number of sources, oil companies, singly or in groups, perhaps licensees in blocks adjacent to the promoted well (which perhaps own infrastructure and/or a field into which to tie any hydrocarbons produced), finance houses, and banks. There is a presumption that all possible sources of investment are aware of the opportunities provided by the Promote licence. It is important that those funding such projects understand fully the opportunities and risks involved.

Finance can be sought at any time for the project – but the earlier that this is done the better, so that those funding the project may continually assess the evaluation of 'risk'.

The DTI's 'UK Prospect Expo 2003', scheduled for 18–19 November 2003 at the Barbican Centre, should provide a test of the interest in oil and gas exploration by the investment community.

Legal assistance

There will also need to be legal involvement for Joint Operating Agreements in the light of success and options for equity arrangements in any subsequent development of the asset.

Risks and chances of success

Currently the chance of success of finding hydrocarbons in a well drilled to established targets ranges from 1 in 5 to 1 in 10. However, for untested concepts the initial 'risks' will inevitably be greater for a first well, simply because there may not have been previous drilling to establish the existence of a source or reservoir rock.

This was the case when drilling commenced on the UKCS in 1964 in the southern gas basin, although the Groningen field was by then discovered. Subsequently, the Brent field was drilled in the northern North Sea for which there was no onshore analogy.

Tax incentives

There is a case to be made for tax concessions on genuine and defined projects related to new exploration plays, whether drilled by licence holders or 'promoters'. The announcement in the 2003 Budget offering consultation on the tax regime relating to exploration activity is obviously a good start. (see **www.og.dti.gov.uk/consultations/conllexp.htm**)

Revenue from oil and gas production is set to decline as production falls, so it is in the long-term interests of the UK Government to encourage the finding and development of new reserves. Such an initiative might go some way to raising awareness of the potential of the UKCS again.

Reducing confidentiality period
A reduction in the period of confidentiality for wells from five years to three years has been incorporated into licences issued for the 20th and future rounds. At the same time consideration is being given to earlier release and/or availability of seismic data. This could be linked perhaps to the renewal of exploration licences.

New seismic acquisition
Seismic contractors need to be alerted to the need for new data to be acquired over areas perhaps un-surveyed for some time and for experimental data aimed at imaging deeper potential and to recognise new plays and targets. Ways of involving contractors in the rewards of 'promote' ventures may also need to be considered.

The need to interpret and map new plays is crucial to their success and so a dialogue with seismic contractors will prove positive.

The way forward

There is a need to draw together those aspects that are not currently being fully addressed and to share concerns and the ways forward for exploration with all those involved in exploration and production on the UKCS, especially politicians and civil servants from the Treasury. This dialogue might take the form of a seminar, or workshop, building on the consultation announced in the Budget – the goal being to inform about the current position of exploration and to conclude a series of actions to be undertaken by government and licensees.

Such a dialogue needs to take place soon, whilst there is a window of opportunity.

But the low level of exploration activity is not just confined to the UKCS and North-West Europe, it is also endemic in the US where there is a lack of appreciation of the opportunities being lost. A perception exists on both sides of the Atlantic Ocean that alternative sources of energy will bridge the gap. The science, however, does not support such a view.

The time is right for a strenuous debate on where the energy resources to fuel our economies is to come from, and what reasonable percentage of them could come from renewables.

There are sufficient learned societies that might sponsor the debate here in the UK, and in the US, to make the dialogue a robust one. Indeed, such is the seriousness of the issues raised they might just promote the debate in concert.

The full version of this article was orginally published in the UK Department of Trade and Industry's (DTI) Improved Oil Recovery (IOR) eNewsletter, *Issue 5, May 2003.* **www.oir.rml.co.uk/issue5/tp/talking_point.htm**

Reserves reduction rings alarm bells in Norway

Concern is mounting in Norway about the country's long-term exploration and production prospects. Poor exploration results in the Norwegian Sea – supposedly the location of large undiscovered gas reserves – are one of the main elements ringing alarm bells, reports *Nick Terdre*.

Saipem crane-barge *S7000* completed installation of Statoil's Kvitebjørn platform earlier this year. Start-up is scheduled for October 2004
Photo: Statoil/Rune Johansen

The seriousness of the situation has now been officially recognised – in its new resource report, the Norwegian Petroleum Directorate (NPD) estimates total oil and gas reserves, discovered and undiscovered, to be down by 7% to 80.5bn boe. The NPD, which has reduced its estimate of undiscovered gas reserves in the Norwegian Sea by 36% to 810bn cm, says that expectations of both the size and number of new finds in the Norwegian Sea must be downgraded.

To keep things in perspective, that is still a lot of gas, and there is still a lot of undiscovered hydrocarbons to search for – 21.4bn boe. But there is clearly a worry that the country may be facing a scenario of decline rather than long-term activity.

New licensing system

The situation has led the government to shake up the licensing system, introducing a new regime in which Norwegian Sea acreage will be offered on an annual basis rather than biennially

Nick Terdre **reports on recent North Sea developments outside the UK and Norwegian Continental Shelves.**

Netherlands

The Dutch Government has abolished the depreciation at will provision available to offshore licensees in what may prove to be a short-sighted move to raise additional tax revenue. It will give the government a one-off tax boost of up to €100mn this year, but according to Nogepa – the Netherlands Oil and Gas Exploration and Production Association – will hit future investment hard. Early this year Nogepa reported that 27 projects (including exploration wells and incremental developments) had been cancelled or postponed, and nine were being re-evaluated. Investments worth €780mn had been lost and gas reserves of up to 39bn cm would not be produced, it said.

Of projects already in the pipeline, NAM was verging on start-up on the K15-FK-1 platform in late July. The platform was installed last year by Heerema crane-barge *Thialf* as part of a fast-track project to develop the 11bn cm of gas discovered by exploration well K15-16 in 2001 – one of the largest finds of recent years. It is tied back to K15-FB-1 by an 8-km, 10-inch flexible pipeline laid by Stolt Offshore layship *Discovery*.

NAM is also developing a more modest find in K7. Here a small satellite platform, K7-FB-1, was installed by *Thialf* in July, and a 17-km, 12-inch flowline laid by Stolt layship *Seaway Falcon* back to K7-FD-1. Two production wells will be drilled.

Meanwhile, more than a year after the project was suspended, NAM is still searching for ways to reduce development costs on Neptunus, which involves the K2-FA and G16-FA fields and some shallow gas finds in the A and B quadrants.

Last year Wintershall boosted its presence in Holland by acquiring the Clyde assets from ConocoPhillips. It is pushing ahead with Clyde's projects, including the development of the Q1-B gas field. Here a platform, rather confusingly designated Q4-C, was installed by Seaway heavy lifting lift-vessel *Stanislav Yudin* in July. It is tied back by a 14-km, 16-inch pipeline to Unocal's Hoorn platform in Q1.

In October start-up is due on Wintershall's L5-B satellite platform, which was installed in July by *Thialf*. In August the 6-km, 10-inch pipeline to L8-P4 was due to be laid by Subsea 7's *Skandi Navica* layship. The company also has partners' agreement to proceed with the development of the small Q5-A field as a single-well subsea tie-back to Q8-B.

ATP has moved across the median line from the UK southern basin to acquire NAM's stake in L6d, along with the operatorship. It plans to develop a 1990 find but is still negotiating evacuation arrangements.

Denmark

Gas is in the frame in Denmark, where liberalisation of the gas market has caused sales contracts to be modified to the detriment of producers. As a result the major producers – Dong and the DUC partners A P Møller, ChevronTexaco and Shell have moved to secure new sales outlets by agreeing terms to land gas in the Netherlands via the Nogat pipeline. This will require the installation of a 90-km pipeline from Tyra West to NAM's F3 field centre. The line, which will be some 26 inches in diameter, will be laid by Allseas' layship *Solitaire* later this year.

A large new gas reserve of some 15bn cm is also about to come onstream. This is Halfdan North-East, an amalgamation of the Igor and Sif fields and the gas in the north-east of the Halfdan field. In July Mærsk, the DUC partners' offshore operator, had its development plan for Halfdan North-East approved. In the first stage this calls for three long-reach wells from the Halfdan BA satellite platform. Depending on buyers being found for the gas, further stages will require more wells from Halfdan BA and a new platform on Igor. The gas will be exported to Tyra West through a 24-inch pipeline, again to be installed by *Solitaire* this year.

New facilities, including this flare-tower jacket, have been installed by Heerema crane-barge *Thialf* on Mærsk's Halfdan field this summer
Photo: Heerema Marine Contractors

Meanwhile, Dong is leading an initiative known as the Synergy Alliance for Marginal Fields to find a viable way of developing four 'stranded' fields in which it has an interest – Amalie and Hejre, and the Freja-Mjølner and Trym fields just across the median line with Norway. The plan is to tie them back with two pipelines, one linking Freja-Mjølner and Hejre, and one Trym and Amalie, to a new process platform at Amerada Hess's Arne South field centre. Earliest start-up would be in 2007.

Dong is also busy round the Siri area, where in July wellhead platforms were installed on the Cecilie and Nini fields. These are tied back to the Siri platform and should come onstream in September. Dong recently made a discovery at Sofie, which lies between Nini and Siri and is likely to be developed using the same infrastructure. The company, which took over as the Siri operator from Statoil last year, is also implementing a two-well subsea development on Siri East Segment 1, which is due onstream in late 2003.

Ireland

Activity is unusually high in the Irish sector, with three developments under way – Corrib, Greensand and Seven Heads. However Corrib, the first approved development off the west coast, has run into problems – in May the planning permission which had been granted for a gas processing terminal on the coast of County Mayo, was withdrawn on appeal. The partners, led by Enterprise Energy Ireland, part of the Shell group, have yet to declare what they will do with the 850bn cf field.

Start-up had been scheduled for January 2004. Now, assuming it still takes place, it will be considerably delayed. The development plan calls for seven subsea production wells connected to a manifold tied back 91 km to shore.

Off the south coast Ramco's Seven Heads project and Marathon's Greensand are proceeding towards start-up in the latter months of this year. Seven Heads, which has recoverable reserves of 300bn cf of gas, is being developed with six subsea wells tied into a manifold connected to Marathon's Kinsale A platform. Greensand involves a single subsea well tied back to Kinsale B. Ramco will next investigate the development potential of the Galley Head field and Midleton prospect.

CSO Apache working on BG's Juno project in 2002 *Photo: Technip*

as before. Even so, it is still under pressure from the industry to provide access to prospective acreage in the Barents Sea and around the Lofoten Islands in the northern Norwegian Sea, where there is currently a moratorium on licensing as it studies the impact of year-round offshore activities. Its report is now out to consultation, but reading between the lines it seems clear that Oslo's conclusion is that the oil industry can co-exist in harmony with other seas users without damaging the environment.

There is a development currently under way in the Barents Sea – Statoil's Snøhvit LNG project, due onstream in 2006, which is exempt from any future ban on offshore activity. But a decision on future projects is of crucial importance to Norsk Agip, which plans to appraise its Goliat find this autumn in hopes of boosting the 50mn barrels already proven. Government and reserves permitting, the company plans to develop the field with a production ship.

Gas treaty delayed

Meanwhile Norsk Hydro's 375bn cm Ormen Lange gas development requires a green light in the shape of a new Norway/UK gas treaty, to permit new export pipelines to be built to the UK mainland. Delays in agreeing the terms of the treaty, which had been expected in March, are causing some concern, as recent statements by both the Hydro and Statoil heads, Eivind Reiten and Olav Fjell, have indicated. Hydro plans to build a 1,200-km export pipeline from the Ormen Lange terminal – 600 km down to the Sleipner hub, from where pipelines to the Continent can be accessed, and a further 600 km to the English east coast. It plans to seek approval for both the subsea field development and the export pipeline in the fourth quarter. Start-up is scheduled for 2007.

Elsewhere in the Norwegian Sea Statoil is on track to bring the Kristin gas condensate field onstream in 2005. Drilling by the semisub *Scarabeo 5* is due to begin shortly.

Ekofisk still growing

Down in the North Sea the major projects concern existing fields. In May this year ConocoPhillips received approval for a third major stage of development of Ekofisk. Costing NKr8.1bn, the project aims to recover a further 182 boe from the Ekofisk and Eldfisk fields, with a new 30-slot wellhead platform, 2/4 M, on Ekofisk and an increase of processing capacity on existing platforms.

Statoil has recommended to its partners that the most cost-effective means of securing the future of the Tampen area, which contains the Statfjørd, Gullfaks and Snorre fields and various satellites, is the debottlenecking of existing facilities.

Redevelopment of BP's Valhall field is also being planned. Later this year the field partners are expected to decide on a plan to install new processing and accommodation facilities – either on two separate platforms or a combined one. Production began in May from a new wellhead platform on Valhall's south flank, and a platform on the north flank is due onstream in the fourth quarter. By that time BP also hopes to sort out problems in piling a new water injection platform at the field centre and bring it into operation.

Grane nears start-up

Heading new developments in the North Sea is Norsk Hydro's Grane field, which, with 704mn barrels of reserves, is the largest discovery not yet in production in the North Sea. Start-up is scheduled for October 2003. Twelve of the 35 planned wells have been predrilled, and drilling is now under way from the platform, which was installed in April and May.

In June Marathon concluded a successful exploration/appraisal campaign in the west Heimdal area, and now plans a multi-field development including the Kameleon, Gekko and Kneler fields. Options include a standalone facility or tie-backs to the Heimdal field centre or across the median line to Bruce or Beryl.

Curing subsea subsidence

Offshore Resource Group (ORG) in Stavanger recently concluded an EPIC contract for Statoil on the Vigdis and Tordis subsea fields in the Norwegian sector of the North Sea. With the aid of self-developed equipment and tools, and close cooperation with both the client and ABB, ORG stopped the effect of the subsidence of the base-structure on Statoil's subsea production installation. *Rolf Olavesen* of ORG explains how.

The Statoil-operated Vigdis and Tordis subsea fields are located in the Tampen area, due east of the Statfjørd field. The seabed at this point comprises soft clays, that initiated the subsidence of the subsea installation. The subsidence is understood to be a combined effect of seabed displacement caused by washout from drilling operations and the low density of the clays. Statoil has been working over an extensive period to find a permanent solution to the problem.

One of the primary consequences of the subsidence has been the displacement of the installation's primary 'base' structures, which rest on the seabed. These base structures have been sinking while the valve-trees (also known as Christmas-trees) have maintained their position as they are mounted upon the wellheads that are supported by extensive 30-inch casings which descend into the more stable substrata below the seabed. Consequently, the flowlines between these valve-trees and the base structures are becoming strained as the base structures continue to sink. In the worst-case scenario the entire production of the fields would need to be stopped. However, until recently, the ongoing problem has been temporarily rectified by lifting the flowline structures with use of air-bags and shims, thereby delaying the inevitable consequence of the subsidence problem.

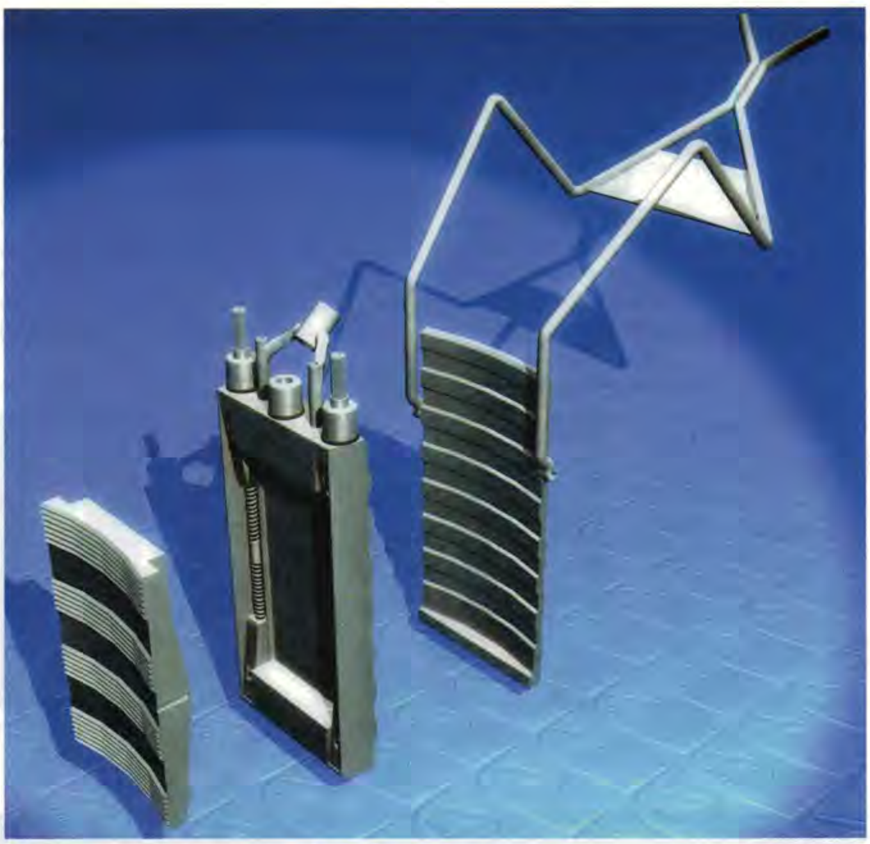
A permanent solution

The project to find a permanent solution to the subsidence problem was initiated in 2001 when Norsk Hydro was the designated operator for the fields in the Tampen area. With the transfer of operations responsibility to Statoil in 2003, the project continued to develop under Statoil's name.

Norsk Hydro engaged the Stavanger-based firm Offshore Resource Group (ORG) to develop a permanent solution to the subsidence problem. Based on a concept originally conceived by the company, ORG designed, fabricated and performed extensive qualification testing on the elected solution, partly in cooperation with ABB who, as the original fabricators of the subsea structures, added invaluable knowledge. The unique solution locks the base structures to the 30-inch casings, thereby hindering the effect of the subsidence on the base structures. ABB performed additional structural analysis to ensure that the solution was compatible with the existing subsea structures.

The equipment was recently installed on a subsea installation on the Vigdis field without the need to stop production during the installation. The concept did not require any modification of the existing subsea structures and was conducted with a remotely operated vehicle (ROV). The installation was performed at depth of 290 metres and was conducted with millimetre accuracy. Similar equipment was subsequently installed on a subsea installation in the Tordis field.

The principal idea behind the solution is based on a ROV-operated system and specially developed hydraulic 'PowerJacks'. The PowerJack concept comprises two toothed steel plates that contain an expandable steel 'diaphragm' between them. With the introduction of hydraulic pressure the diaphragm expands and consequently presses the toothed steel plates into the two structures that require locking. When the desired effect has been achieved a locking mechanism, comprising mechanically actuated wedges, is activated and any movement between the two candidate structures is stopped permanently. In association with more traditional methods and tooling systems, this total-solution proved to be fast, effective and low-cost. ORG was also responsible for the development of all the procedures and methods required for the offshore operation.



'Exploded' view of the PowerJack assembly ***Courtesy of ORG***

Strong growth forecast in subsea sector

It can be said without exaggeration that the emergence of subsea production technology has revolutionised the offshore oil and gas industry. The subsea sector has developed at a remarkable pace in recent years – enabling the economic development not just of fields on the continental shelf, but also in the deeper waters further offshore – and strong market growth is forecast over the period to 2007. *Dominic Harbinson* and *Steve Robertson* of Douglas-Westwood, together with *Dr Roger Knight* of Infield Systems, highlight some of the findings of the companies' recently published *World Subsea Report*.*

Subsea production occurs when the bore of an offshore well terminates or is 'completed' in a wellhead located on the seabed; quite distinct from a surface completion where the well tubing continues up to the deck of an offshore platform. Production from the subsea well is routed through a pipeline running along the seabed and up to a 'host' platform. Control of the subsea well is achieved via a control line or 'umbilical' running from this host platform.

The first applications of subsea production technology occurred in the US in the early 1960s and, a decade later, the operator Hamilton Brothers pioneered its use in the harsher waters of the North Sea using subsea wells connected to a converted semi-submersible drilling rig to produce the UK's first offshore oil from the Argyll field in 1975. For a variety of reasons other operators were hesitant to follow this lead and significant growth in subsea production did not really begin until the 1980s, with the main poles of activity being the UK sector of the North Sea and the waters of the Campos Basin off southeastern Brazil. In the US, despite the early pioneering work, subsea activity remained rather muted until the discovery of deepwater reserves in the Gulf of Mexico, which prompted a surge of applications beginning in the mid-1990s.

Subsea drivers

The four main drivers behind the growth in subsea activity identified in the report are discussed below. These drivers are reinforced by the substantial cost reductions that have been achieved in the subsea sector as a result of a number of factors, notably technological advances, improved business procedures and government support.

Deepwater

The influence of water depth on the choice of surface or subsea production is clearly shown in **Figure 1**. The graph is based on the numbers of offshore wells that came onstream worldwide over the period 1998–2002, as identified by the Infield database. The figure plots the proportion of these wells that are located on the seabed (subsea wells) against the proportion that are located on the deck of a production facility (surface wells), across the full range of water depths.

The figure shows how, in water depths (WDs) of less than 100 metres, surface wells are overwhelmingly predominant. However, once WDs exceed the conventional limit of fixed platform installations (ie above 200 metres), the use of subsea wells tends to be favoured. It is interesting to note that for deepwater developments (those in WDs greater than or equal to 500 metres) the proportion of surface wells increases. This reflects the importance of dry completion units – spars and tension leg platforms (TLPs) – in future deepwater projects, particularly in the US Gulf of Mexico.

Marginal fields

The use of subsea wells connected back to existing infrastructure can be a very cost-effective way of draining reservoirs that are either too small or too complex to merit a 'stand-alone' development with its own dedicated production facility. Over 30% of the 496 greenfield

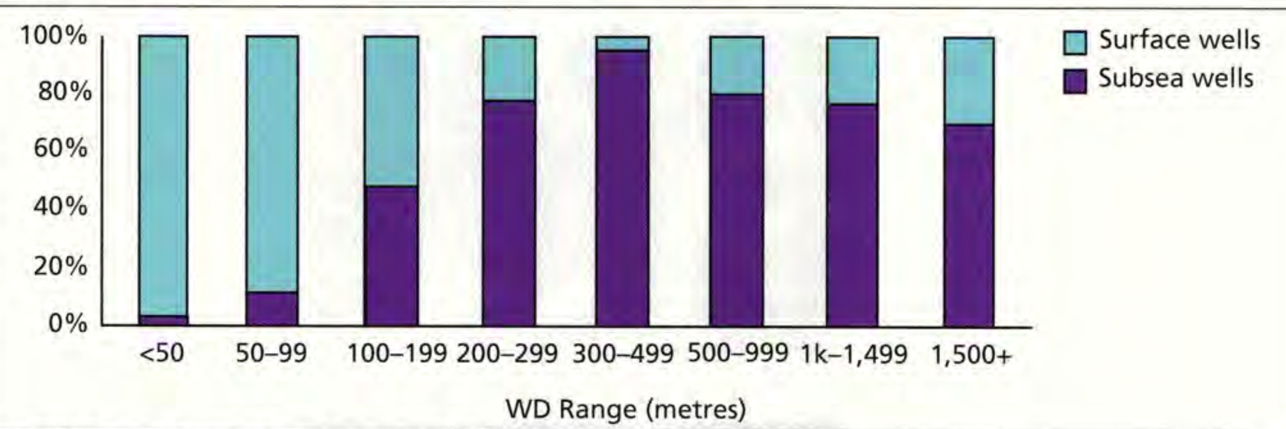


Figure 1: Water depth distribution of surface and subsea wells, 1998–2002 (%)
Source: The World Subsea Report, *Douglas-Westwood & Infield Systems*

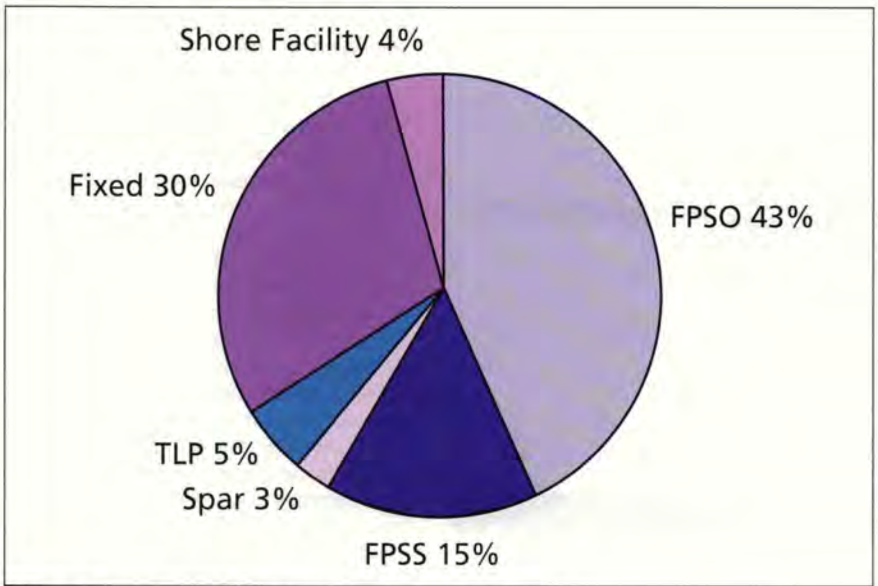


Figure 2: Host facilities for subsea well prospects 2003–2007

subsea prospects identified for the 2003–2007 period are targeting reserves of less than 20mn boe and more than half are targeting reserves of less than 50mn boe.

Fast-track/Phased projects
Subsea completions enable operators to 'fast track' development of a field or part of a field, thereby anticipating production and bringing an earlier start to the project's revenue stream. A good example of this 'fast-track' strategy was the Ceiba field in WD 700 metres off Equatorial Guinea. The use of subsea production technology associated with a leased FPSO, the *Sendje Berge*, enabled the operator Triton (now part of Amerada Hess) to achieve first oil from the field on 22 November 2000, less than 14 months after the field's discovery by Diamond Offshore's semi-submersible rig *Ocean Alliance* in August 1999.

Floating production
The increasing adoption of floating production systems (particularly FPSOs) is a very strong driver for the subsea industry. **Figure 2** shows the proportion of the 2,076 subsea wells in prospect worldwide for the 2003–2007 period that will be hosted by the various platform types, whether as satellite projects or as part of a variety of stand-alone developments.

Clearly, floating production systems (FPSs) are by far the most common host facility, accounting for 66% of the subsea wells planned or possible over the period to 2007. Within the floating production sector, FPSOs are strongly predominant, accounting for almost 900 of the subsea wells identified under current project plans. Despite the dominance of FPSs, however, fixed platforms will play a very important role in future subsea developments, hosting 30% of the future wells.

Subsea prospects
Figure 3 shows the regional distribution of subsea wells installed during the 1998–2002 period and those that are planned/possible (prospects) for the period 2003–2007.

Over the past five years, three regions – Western Europe, North America and Latin America – accounted for almost 90% of global subsea well installations. In the coming five-year period their dominance is set to diminish somewhat as a result of strong growth in the African region. Here, the number of subsea well installations could increase more than four-fold, with almost 500 wells in prospect for the 2003–2007 period, compared to the 110 that were brought onstream in the 1998–2002 period.

The Infield data suggest that all regions could see an increase in subsea activity over the next five years. However, it must be remembered that a number of the future prospects currently identified on the database may not actually move ahead, while others may be postponed beyond the time-frame of the report. Our forecasts for the subsea market, which attempt to reflect this reality, are summarised below.

Subsea sector capex

Over the 2003–2007 period, we anticipate that subsea developments on both greenfield and brownfield projects worldwide will require the installation

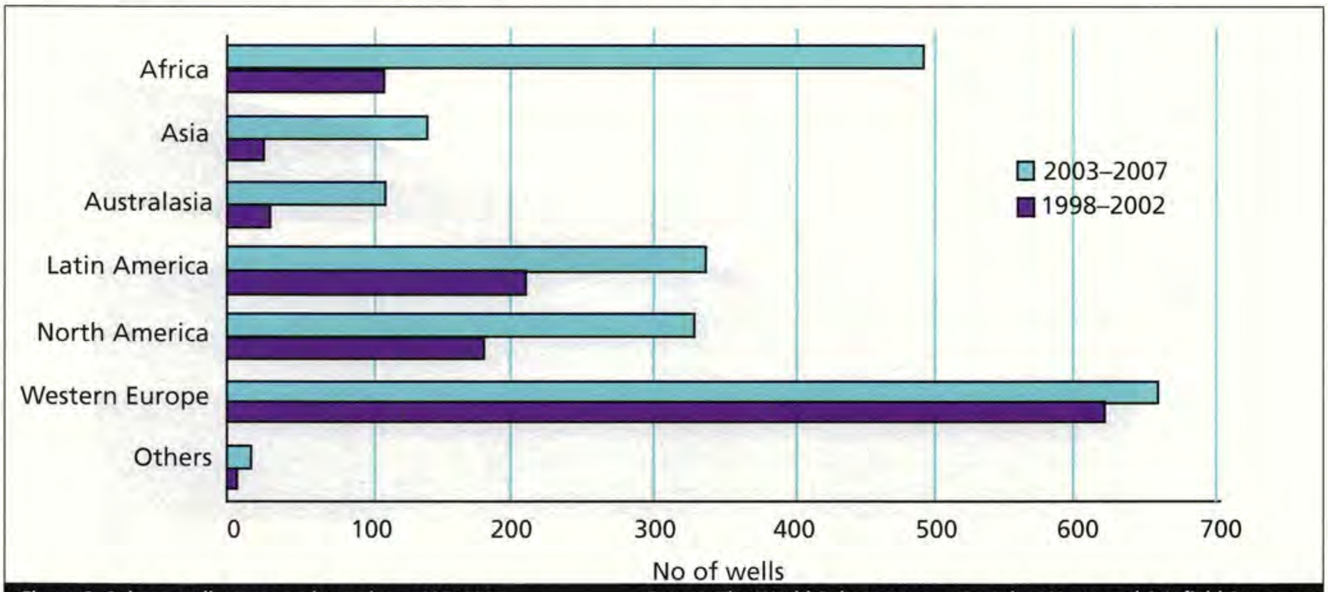


Figure 3: Subsea well prospects by region, 1998–2007 *Source:* The World Subsea Report, *Douglas-Westwood & Infield Systems*

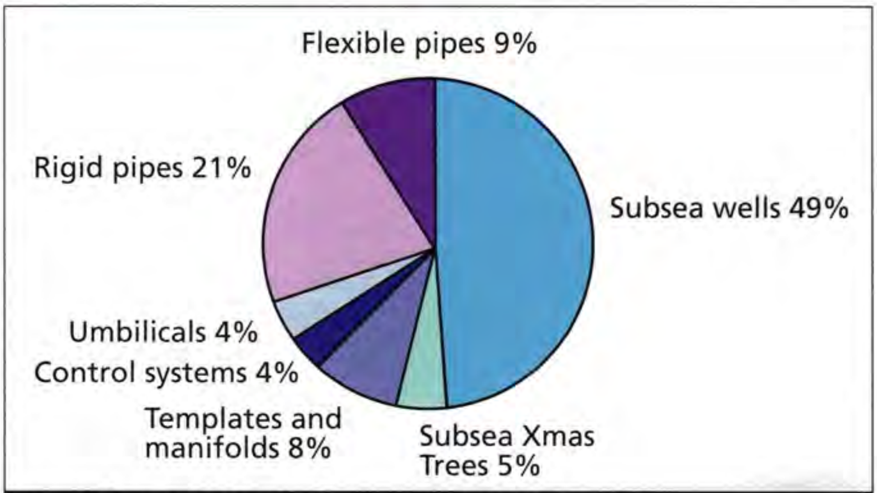


Figure 4: Global subsea capex by component, 2003–2007 (%)

of 1,626 subsea wells (both production and injection), and almost 400 templates and manifolds. In addition, some 5,600 km of control lines and over 10,000 km of seabed pipelines (both rigid and flexible) will be laid to or from these subsea units. (See **Figure 4**.)

It is forecast that global capex in the subsea sector over the five-year period to 2007 will amount to $48.6bn – an increase of more than 40% relative to the levels recorded in the 1998–2002 period. The average value of the global subsea market will rise from $6.8bn/y in 1998–2002 to $9.7bn/y over the 2003–2007 period.

The drilling and completion of subsea development wells represent the most significant market segment in value terms, amounting to nearly $23.5bn – almost half of the total capex forecast for the 2003–2007 period. Pipelines, both rigid and flexible, make up the next biggest market segment with a combined forecast capex of nearly $15bn, or 30% of the estimated market value over the period to 2007.

The historic importance of activity off Western Europe is very clearly shown in **Figure 5**, as is the emergence of Africa as a very significant subsea region. Capex in this latter region is expected to exceed $12bn over the period to 2007 – almost four times the levels recorded in the previous five-year period. In contrast, spending off Western Europe is expected to decline slightly, but this will be more than offset by steady growth in the other two major subsea regions – North America (particularly the US Gulf of Mexico) and Latin America (Brazil).

Our forecasts also indicate that, for the first time, the number of subsea wells coming onstream in deepwater (WDs greater than 500 metres) over the 2003–2007 period will actually exceed those coming onstream in shallow water.

This forecast level of deepwater activity represents a 170% increase on the previous five-year deepwater total and relates principally to activity off Africa, Latin America (Brazil) and North America (the US Gulf of Mexico). Capex in the deepwater subsea segment is also expected to exceed that in shallow water.

We believe that subsea activity over the period to 2007 could exceed the levels indicated above. There are two main reasons for this. Our forecasts are based on *identified* subsea development prospects. In addition to these, there are currently 244 development prospects that could be brought onstream over the period to 2007, for which no development scheme has yet been announced. A fair number of these may eventually be developed using subsea technologies.

Additional development prospects will also emerge over the 2003–2007 period as a result of ongoing exploration activity. Given the speed with which subsea projects can be implemented, it is possible that some future discoveries made, for example, as late as 2005 or 2006, could be developed and producing through subsea wells by year-end 2007.

It is our view that the potential for currently 'invisible' subsea development prospects to emerge over the period to 2007 is particularly strong in the North American region – most notably in the US Gulf of Mexico, arguably the most dynamic and fastest-moving offshore province in the world.

*The World Subsea Report 2003–2007 *is published by Douglas-Westwood and Infield Systems. For further details visit* **www.dw-1.com** *e:***admin@dw-1.com** *or T: +44 (0)1227 780999.*

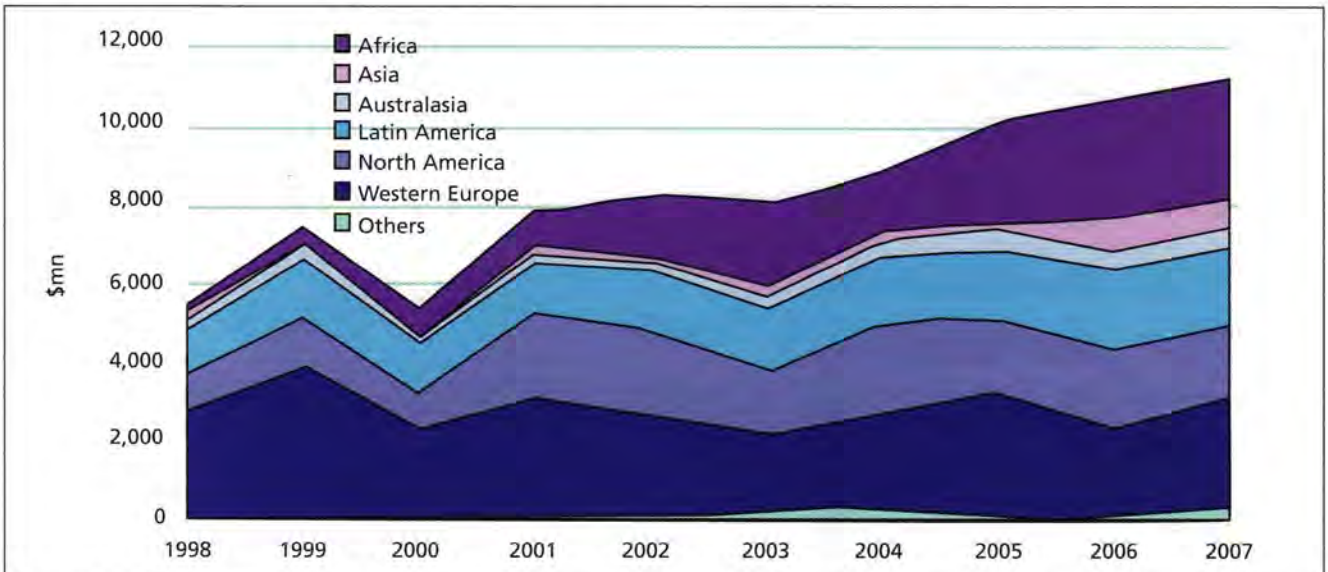


Figure 5: The global subsea market in $mn, 1998–2007 *Source:* The World Subsea Report, *Douglas-Westwood & Infield Systems*

TRAINING COURSES 2003

Retail Marketing

Course Dates:
16 - 19 September, 2003
Course Venue:
London, UK
IP Member:
£1900.00
(£2232.50 inc VAT)
Non-Member:
£2100.00
(£2467.50 inc VAT)

This **four-day course** examines retail marketing and its related activities, including the manufacture and qualities of petrol, the fundamentals behind a network, market and location analysis, trade channels, product lifecycle, the importance of non-fuel stocks and activities to the business, and much more. All topics covered will be related specifically to retail oil operations, and will be assisted by short practical assignments.

Who Should Attend?

Oil company retail operations' personnel, analysts, refiners, those from supply and distribution, management accounts, engineering, asset and property management functions, sales and marketing, marketing communications, customer services, and external suppliers of shop goods and site equipment.

Supply and Distribution: Organisation, Operations and Economics

This **four-day course** will examine the impact on supply and distribution of: refineries' output and fuels' specifications; product sourcing - parent-company refinery, open-market, ex-rack, exchanges; primary-supply mechanisms used; terminal design and location. The overall effect of the network, network planning, and that of competitor locations on routing, load optimisation and backhauling operations will be discussed, as well as the benefits of multi-shift delivery patterns. Staffing levels and training, safety and environmental issues, transport operations (in-house and contract haulage), together with benchmarking techniques allowing the assessment of performance against competitors to identify opportunities for improvement will also be scrutinised.

Course Dates:
23 - 26 September, 2003
Course Venue:
London, UK
IP Member:
£1900.00
(£2232.50 inc VAT)
Non-Member:
£2100.00
(£2467.50 inc VAT)

Planning and Economics of Refinery Operations

in association with **enspm** FORMATION INDUSTRIE

Course Dates:
7 - 10 October, 2003
Course Venue: **London, UK**
IP Member:
£1900.00 (£2232.50 inc VAT)
Non-Member:
£2100.00 (£2467.50 inc VAT)

This intensive **four-day course** will enable delegates to understand the essential elements of refinery operations and investment economics, reviewing the various parameters affecting refinery profitability, and to develop a working knowledge of the management tools used in the refining industry.

Who Should Attend?

- Technical, operating, and engineering personnel in the refining industry
- Trading and commercial specialists
- Analysts and planners
- Independent consultants
- Process licensors
- Catalyst manufacturers and refining subcontractors

Fundamentals of the Oil and Gas Industry

This **three-day course** provides a core understanding of the oil and gas industry, from upstream exploration and production to downstream refining, sales and marketing. Under the guidance of an expert course faculty, participants will develop awareness of the business and an appreciation of key issues. The course will help delegates to appreciate the dynamics of the industry and, through the use of specially designed exercises, allow them to gain hands-on experience of key aspects of it.

Who Should Attend?

- Those requiring an understanding of the energy value chain
- Analysts and planners
- New recruits, traders, bankers, lawyers, and consultants working with energy companies

Course Dates:
15 -17 October, 2003
Course Venue:
London, UK
IP Member:
£1400.00
(£1645.00 inc VAT)
Non-Member:
£1600.00
(£1880.00 inc VAT)

Introduction to Lubricants

Course Dates:
23 - 24 October, 2003
Course Venue:
London, UK
IP Member:
£1000.00
(£1175.00 inc VAT)
Non-Member:
£1200.00
(£1410.00 inc VAT)

This **two-day course** provides an overview of the lubricants business for those personnel needing a working knowledge of it, but in a limited amount of technical detail. The broad scope of the course will allow those new to the industry, or those with some experience of it, to draw immediate benefits from their increased knowledge to the advantage of themselves and their organisations.

The importance of lubricants within an oil company product portfolio will be explained and the course will provide a sound background to those engaged in sales, marketing, and planning strategy, and the purchase and use of lubricants, enabling them to make informed decisions. The environmental aspects of lubricants will be explored during the programme, together with their impact on the business itself.

Hazardous Area Classification - IP 15

This **two-day course** is designed to provide a technical overview and to introduce the delegate to the many facets of area classification using the latest IP Code (IP 15). The course will take delegates through the various methodologies and give time to partake both individually and as a syndicate in exercises using the various methodologies. The course will allow sufficient time for discussion and questions regarding the code.

Who Should Attend?

- Technical, operating, engineering, and electrical engineering personnel seeking an in-depth view of area classification
- Those new to the industry, including graduate trainees, who require a concise introduction to area classification.

Course Dates:
3 - 4 November, 2003
Course Venue:
London, UK
IP Member:
£1000.00
(£1175.00 inc VAT)
Non-Member:
£1200.00
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Impact of new entrants in UK North Sea

Following the recent high-profile entries of Apache and Perenco to the UK sector of the North Sea, coupled with current interest in the sector by many other companies, independent consultant *Wood Mackenzie* examines how the addition of new entrants over the last ten years has impacted the corporate make-up and development of the UK Continental Shelf (UKCS).

There are many factors that make the UKCS an attractive option for investment. These include a relatively stable political and regulatory environment, a relatively attractive fiscal regime (despite the Budget changes in 2002), extensive infrastructure plus over 300 fields producing around 4mn boe/d. Entry into the UKCS is also facilitated by the relatively liquid asset market.

Some 43 new entrants over the last ten years have acquired interests in commercial fields in the UKCS and a further 15 have acquired an interest in exploration acreage only (see **Figure 1**). The vast majority of these companies have been from the independent sector. Of the 58 new entrants, 20 have entered through the acquisition of companies or company subsidiaries, 17 have entered through the acquisitions of commercial fields on the asset market and 21 have entered by acquiring acreage and technical reserves (as classified at the time of the deal).

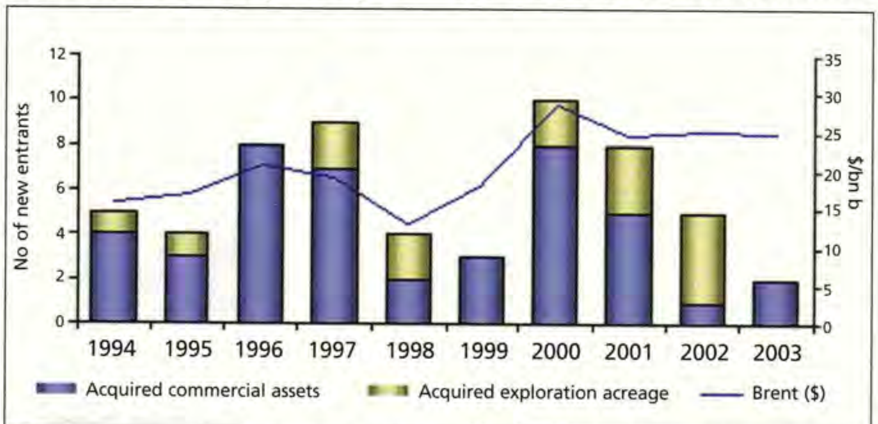


Figure 1: New entrants to UKCS, 1994–2003 (up to June 2003) *Source: Wood Mackenzie*

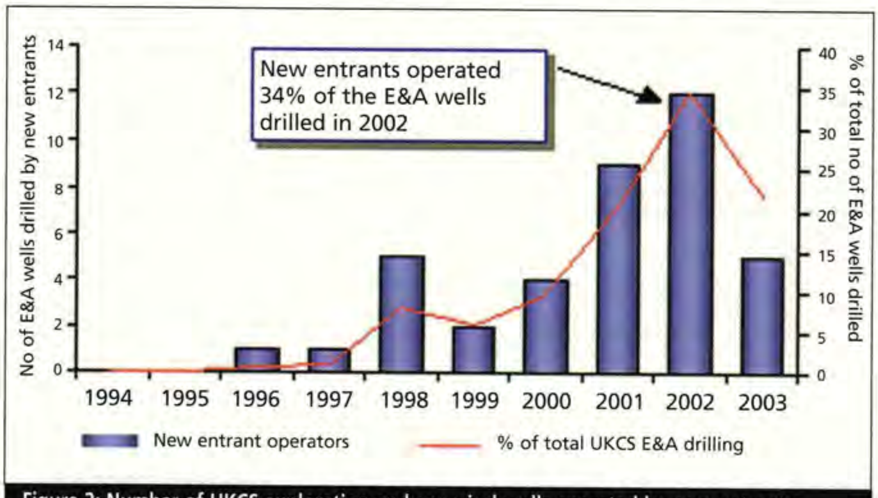


Figure 2: Number of UKCS exploration and appraisal wells operated by new entrants, 1994–2003 (up to June 2003) *Source: Wood Mackenzie*

Whilst companies who entered the UK after 1994 represent nearly half of the overall companies currently in possession of commercial interests (27 of the 55 companies), at present they account for only around 15% of the UK's remaining commercial reserves. The incumbent supermajors and majors still dominate the top tier of the rankings table – see **Table 1**. Importantly, however, the majority of the new entrants have been from the independent sector and the portfolios they have managed to build are significant for companies of their size. Furthermore, exploration and appraisal trends suggest that new entrants are accounting for an increasing share of well operatorships, with 34% of the wells drilled in 2002 being operated by new entrants (see **Figure 2**).

A significant number of companies are either currently looking to acquire or are considering acquiring assets in the UK. As with the new entrants over the last ten years, these potential new entrants represent a broad spectrum of companies. They include international independents, new start-up companies, national oil companies, and groups from the service sector. If new entrants are to be successful, however, they will need to be prepared to focus on developing the smaller opportunities that exist in the mature North Sea basin.

As highlighted by **Table 1**, the supermajors and majors have significant positions in the UK. These companies are expected to continue to be active in the region through significant brownfield investment and the development of fields around their key assets. However, as the sector continues to mature the material value of some of these developments in their global portfolios will decline. The rationalisation of such assets will fuel the liquid asset market and potentially encourage further new entrants. The success of recent new entrants in building significant portfolios and the current government/ industry initiatives will provide further encouragement for those companies considering entry into the region.

Range of entrants

Of the 15 companies who have entered the UK but not acquired commercial assets, three only hold acreage in the West of Shetlands sector – Anadarko, Atlantic Petroleum and DONG – whilst a further four acquired acreage in the 20th Licensing Round in 2002 – Egdon Resources, Oilexco, Reach and Warwick Resources. Due to the recent licensing and frontier nature of these blocks, further exploration is likely on this acreage which could yield commercial reserves.

The vast majority of the companies entering the sector over the last ten years have been from the independent sector. These companies range from the very smallest new starts such as Dana Petroleum, First Oil and Acorn Oil and Gas, to the established international independents such as Burlington Resources and, more recently, Apache.

A significant number of the larger independents have been North American companies. The UK sector provides an opportunity for these companies to grow an international portfolio by employing low cost operations learnt from their North American businesses and exploiting exploration and brownfield opportunities. The success of Talisman in building a significant portfolio has encouraged others to follow.

In addition to the independents, one national oil company and four utility companies have entered the UK upstream sector since 1994. Three of these – Eastern Natural Gas, Northern Electric and Yorkshire Electricity – did so in 1994 as companies looked to secure equity gas in the newly liberalised gas and power markets. More recently, the German utility RWE-Dea entered the UK sector through its acquisition of Highland Energy, again with the aim of securing equity gas.

The number of entries by year shows two peaks, in 1996–1997 and 2000–2001, both of which coincide with upturns in the price of oil. The cash flow generated by high oil prices allows oil companies to expand their operations into new international areas such as the UK. In addition, new start companies are more likely to secure funding in such a positive oil price environment.

The 1996–1997 peak featured a significant number of new companies entering the UKCS via the acquisition of existing UKCS players. Included in this were new entrants Melrose Resources, Samedan, Saga, CalEnergy and Gulf Canada who acquired Pentex Petroleum, EDC, Santa Fe Energy, Northern Electric, and Clyde Petroleum, respectively. The 2000–2001 peak includes six new start companies – Acorn Oil and Gas, Atlantic Petroleum, Consort Resources, Highland Energy, Tuscan Energy and West Oil. The employee spin-off from the mergers and mega-mergers of 1998–2000 to some extent facilitated the emergence of these new starts.

Ranking	Company	Remaining reserves (mn boe)	Year of entry
1	BP	2,127.1	Pre-1994
2	Shell	1,575.3	Pre-1994
3	ExxonMobil	1,364.0	Pre-1994
4	Total	1,012.0	Pre-1994
5	ConocoPhillips	827.8	Pre-1994
6	ChevronTexaco	582.3	Pre-1994
7	BG	557.9	Pre-1994
8	Eni	467.7	Pre-1994
9	Centrica	437.3	Pre-1994
10	Amerada Hess	401.7	Pre-1994
11	Talisman	374.7	1994
12	Kerr-McGee	265.8	Pre-1994
13	EnCana Corporation	246.1	1996
14	Intrepid Energy	208.7	1997
15	Marathon	192.6	Pre-1994
16	Apache	180.5	2003
17	Canadian Natural Resources	155.3	2000
18	Gaz de France	148.9	Pre-1994
19	BHP Billiton	131.9	Pre-1994
20	Petro-Canada	107.6	2002
21	Burlington Resources	105.5	1997
22	RWE Dea	78.5	2001
23	Nippon Oil Corporation	69.0	Pre-1994
24	DNO	68.3	Pre-1994
25	Iranian Oil	68.3	Pre-1994
26	Statoil	65.8	Pre-1994
27	Paladin	60.7	1998
28	Perenco	50.8	2003
29	Consort Resources	48.0	2000
30	Ruhrgas	45.3	Pre-1994
31	OMV	44.6	Pre-1994
32	Oranje Nassau Energie	40.4	1995
33	Murphy Oil	39.3	Pre-1994
34	Venture Production	38.2	2000
35	Dana Petroleum	37.0	1997
36	Premier	34.5	Pre-1994
37	Tullow Oil	28.9	2000
38	Edinburgh Oil & Gas	25.7	2001
39	KNOC	25.2	1995
40	Marubeni	22.8	2000
41	Energy Africa	18.9	1996
42	Tuscan Energy	16.3	2001
43	Dyas	14.7	2000
44	First Oil	12.7	1999
45	Noble Energy	9.5	1996
46	ATP Oil & Gas	9.0	2001
47	Acorn Oil & Gas	8.8	2001
48	Sumitomo	6.9	Pre-1994
49	Cairn Energy	6.1	Pre-1994
50	Itochu	5.7	Pre-1994
51	Bow Valley Energy	5.0	1996
52	Svenska Petroleum	4.6	Pre-1994
53	Edison	1.0	Pre-1994
54	CalEnergy	0.8	1997
55	Pentex Energy	0.6	Pre-1994

** Data extracted from Wood Mackenzie's Corporate Analysis Tool (CAT) product in May 2003.*

Table 1: UK companies ranked by commercial reserves (mn boe)* *Source: Wood Mackenzie*

Final round-up

Nearly 60 new players have entered the UK sector over the last ten years. These new entrants currently only hold around 15% (1.7bn boe) of the remaining 10.4bn boe of commercial reserves on the UKCS. However, they are becoming increasingly active in terms of UKCS exploration and appraisal drilling, with 34% of all the exploration and appraisal wells drilled in 2002 being operated by new entrants.

The majors and supermajors still dominate the remaining reserves with none of the new entrants managing to break into the top 10 ranking by commercial reserves or asset value. Importantly, however, the majority of the new entrants have been from the independent sector, and the portfolios they have managed to build are significant for companies of their size. Some of the most successful companies at growing a substantial position have been extremely active in the asset market. Companies such as Canadian Natural Resources and Talisman have all averaged over two deals a year since entering the sector.

In contrast to the traditional view in a mature basin, EnCana and Edinburgh Oil and Gas have grown their portfolio through exploration with the discovery of the Buzzard field. The discovery highlights that a different perspective brought by new entrants can result in significant developments.

A number of companies have recently made high value entry deals, such as Apache, Perenco, Petro-Canada and RWE-Dea. All four are expected to pursue growth opportunities in the sector and could build substantial portfolios and positively impact the development of the UKCS.

As highlighted by **Table 1**, the supermajors and majors hold significant positions in the UK. They are expected to continue to be active in the region through significant brownfield investment and the development of fields around their key assets. However, as the sector continues to mature the material value of some of these developments will decline. The rationalisation of such assets will fuel the asset market and potentially encourage further new entrants.

A variety of companies are currently considering entry into the UK or are actively pursuing opportunities. The range of companies looking highlights the opportunities that exist in the market. The success of recent new entrants in building significant portfolios and the current government/industry initiatives will provide further encouragement for these companies.

For more information, contact Scott Hadden on T: +44 (0)131 243 4291 or e: **scott.hadden@woodmac.com**

Energy Institute launches

As we anticipated and advised readers in the last merger update, we are delighted to confirm that the Energy Institute was legally created on 1 July 2003. This means that members of the IP and InstE are founding members of the Energy Institute. As your membership grade converts to the EI grade as shown in the Merger Prospectus (page 11), the designatory letters you have been using now also change (see p44 this issue).

During July and August the staff and systems were co-located to 61 New Cavendish Street, the home of the Energy Institute. To thank the EI's staff team, Council and Committee Members for their contribution to on-going merger activities, a reception was held, following the most recent Council meeting, on 31 July, attended by more than 80 guests. At the reception Louise Kingham, the Energy Institute's Chief Executive, thanked members and staff most sincerely for their support: 'Without your participation, guidance and often your patience we would not be here today celebrating the creation of the Energy Institute. For that I am most grateful to you all, including those who could not be with us today.'

It is hoped that as many members as possible will join in the celebrations to launch the Energy Institute at a series of national and regional events being held from the beginning of September and that these events encourage members of both former Institutes to get to know each other. Please visit the website – **www.energyinst.org.uk** – for details of timings and locations.

Professor Martin Fry, InstE President, and Dr Pierre Jungels CBE, IP President, will continue to co-chair the Energy Institute's Council until the winter of this year, when the first General Meeting of the Energy Institute will convene to record the outcome of the Council elections. At the same time, the first President of the Energy Institute will be appointed.

New structure

The new EI Branch structure was agreed at the last Council meeting. There are now 16 established Branches (13 in the UK and three overseas – Ireland, Netherlands and Hong Kong). These Branches have been developed in consultation with the original Branch committees and their members. We will be contacting members to check that affiliation to their Branch within the new structure is still appropriate. If not, this can easily be amended. Over the next few months new Branches in Geneva and Houston will also be established.

The Energy Institute has developed a new structure for Group Membership (formerly Corporate Membership), with three distinct grades of membership – Group Member, Technical Group Member and Energy Institute Partner. A new grade of individual membership has been developed to allow individuals a fast-track route into membership without going through the full application process. This level of membership is called Affiliate, and provides all the benefits of membership except those associated with professional recognition. More details on these and the various benefits available from membership can be found in new literature about the Energy Institute, on the website and on p44 of this issue of *Petroleum Review*.

From the beginning of September members will begin to receive correspondence from the Energy Institute and will be able to visit the new website at **www.energyinst.org.uk** In addition, we will be contacting members to continue to deliver the commitments we made in the Merger Prospectus – by seeking your views on some key issues and identifying your future interests.

We would like to take this opportunity to remind you that if you were previously a member of both the IP and the InstE we would appreciate your notification of this, so that we can ensure you receive only one membership subscription renewal this autumn. Please email **membership@energyinst.org.uk**

In the meantime, we will keep you abreast of developments and look forward to seeing you at one or more of the EI's forthcoming launch events over the next few months.

Electrical Safety Code – IP Model Code of Safe Practice in the Petroleum Industry Part 1

This Code provides an overview of the particular issues related to the safe use of electrical equipment in the petroleum industry, specifically in areas where there is a possibility of occurrence of a flammable atmosphere.

Guidance is given on the selection of equipment together with installation, inspection and maintenance practices. Where more detailed guidance on specific topics exists, the relevant references are provided.

This Code is applicable to both onshore and offshore areas, and is closely associated with *IP Model Code of Safe Practice Part 15 area classification code for installations handling flammable fluids.*

This new Code is essential reading for designers, managers, engineers and consultants responsible for the design and specification of safe electrical equipment for petroleum, petrochemical and similar installations handling flammable fluids.

ISBN 0 85293 225 1 Full Price £86.00 25% discount for EI Members 7th edition August 2003

The Stimulation of Nitrate-Reducing Bacteria (NRB) in Oilfield Systems to Control Sulphate-Reducing Bacteria (SRB), Microbiologically Influenced Corrosion (MIC) and Reservoir Souring: An Introductory Review

The use of nitrate as a means of controlling the activity of sulphate-reducing bacteria (SRB) and removing hydrogen sulphide from various industrial systems (oily waste, sewage, etc) is well documented. In recent years, the application of this and related technologies has been proposed (and trials performed) for use in oilfield situations. It has been stated that nitrate technologies may provide a cost effective, efficient and environmentally acceptable means of controlling SRB and remediating hydrogen sulphide contaminated systems, avoiding the use of expensive and environmentally unacceptable organic biocides. Currently, several companies operating oil fields in the North Sea are considering trials with nitrate products to assess their potential to control biological souring of their new or ageing reservoirs. In addition, the use of nitrates as an alternative to organic biocides for the control of SRB and microbial induced corrosion (MIC) in water injection systems has also been proposed.

This review document summarises the technology and addresses the practicalities of applying and monitoring a nitrate treatment in the field. The review document covers the following: a brief summary to introduce nitrate-reducing bacteria (NRB); the impact of nitrate on NRB and SRB activity and corrosion rates topsides; the impact of nitrate on NRB and SRB activity and souring in the reservoir; potential pros and cons with regard to utilising nitrate to control SRB in oil fields.

Essential reading for chemists, microbiologists, petroleum engineers, corrosion engineers, consultants, operating companies, chemical suppliers, research institutes and all those involved in environmental science and protection.

A conference showcasing key areas of the NRB report will be held at the Energy Institute on 9 September 2003. The event will provide a series of worked examples of nitrate use followed by discussion. For more information, contact Laura Viscione on T: +44 (0)20 7467 7174 or visit **www.energyinst.org.uk** (see page *)

ISBN 0 85293 394 0 Full Price £44.00 25% discount for EI Members August 2003

Hydrocarbon Management – Meter Proving – Code of Practice for the Proving of Loading Gantry Meters

This document is a complete revision of the Institute of Petroleum's *Petroleum Measurement Paper No 4, Code of Practice for the Proving of Gantry Meters,* first published in January 1991. It should be read in conjunction with the other relevant Meter Proving documents published as either sections of the *IP Petroleum Measurement Manual Part X Meter Proving or Hydrocarbon Management, Meter Proving Codes.* Details of all these publications can be found at **www.energyinst.org.uk**

This new Code of Practice establishes minimum levels of accuracy for the proving and adjustment of loading gantry meters. It also gives guidance on the traceability of reference devices, and provides information on their maintenance requirements.

The guidance on meter adjustment is based on industry best practice and represents the minimum level of performance acceptable for trade within the industry.

This Code is essential reading for anyone installing, proving or maintaining gantry meters.

ISBN 0 85293 407 6 Full Price £44.00 25% discount for EI Members July 2003

Available for sale from Portland Customer Services, inc. postage in Europe (outside Europe, add £6.00 per order). Contact Portland Customer Services, Commerce Way, Whitehall Industrial Estate, Colchester CO2 8HP, UK.
T: +44 (0)1206 796351. F: +44 (0)1206 799331. e: sales@portland-services.com

Optimising gas compressor performance

Until very recently oil and gas companies have had to rely on the original equipment manufacturers for gas compressor performance analysis. Field conditions are, however, very different from factory test conditions and this has meant that companies have found it difficult to benchmark compressor performance and established life of field economics. In order to address these challenges a Joint Industry Project was inaugurated by MSE (Consultants) of Carshalton. *Petroleum Review* Editor *Chris Skrebowski* interviewed *Adrian Darcy*, Senior Process Engineer, and *Dr Sib Akhtar*, Managing Director, to find out more.

Dr Akhtar explained that in their work as engineering consultants specialising in compressors and gas turbines for the oil and gas industry it had become clear that compressor performance was a key element in field profitability, but one about which the industry had only limited knowledge. Although individuals talked to each other and specialist consultants such as MSE had a great deal of detailed knowledge about compressor problems, there was no systematic analysis that would allow companies to compare and benchmark their performance.

According to Dr Akhtar it became clear to MSE that by gathering and securely saving performance data on the actual operation of compressors and then making the data available securely and anonymously over the Internet they could build a system that would allow companies to benchmark their performance. Providing them with all the relevant data would allow them to compare their equipment performance against similar and rival compressor systems and weigh these against the manufacturers' claims. In addition, decisions on the optimal timing for compressor 're-wheeling' or reconfiguration could be made more effectively and more confidently. Finally, by providing some clearer ideas about compressor performance over time a better idea of life cycle costs could be built up. He explained that machinery engineers' choice of equipment often got overruled by project managers in favour of lowest initial costs because of lack of data to show which option had the lower life-cycle costs.

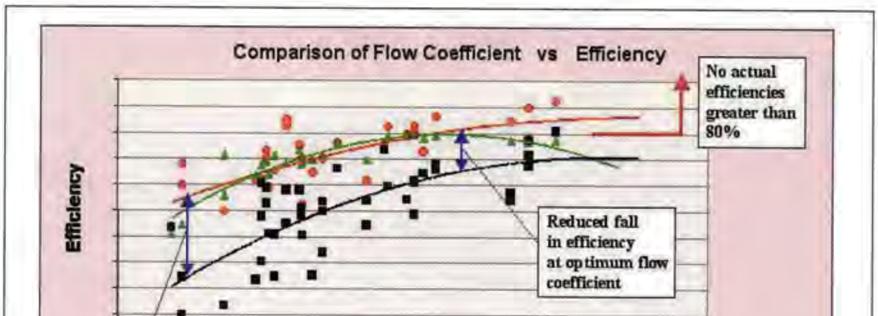


Figure 1: Comparison of flow coefficient vs efficiency – this shows how important compressor selection is to performance retention

Joint industry project

Encouragement from a number of companies led MSE to set up the first ever Joint Industry Project (JIP) for 'Optimum centrifugal compressor performance in the hydrocarbon gas industry', in September 2002. The initial participants in the JIP were BG Group, British Gas (Hydrocarbon Resources), Conoco Phillips and Eni Lasmo. BP is the latest company to sign up to the JIP.

Adrian Darcy stressed, however, that in the case of an industry study like this it really is a case of the 'more the merrier'. With all the monitoring and recording systems now established and proved it is relatively easy to add in more compressors and more companies, he noted. Increasing the database will improve the confidence of the users, improve the data range and further improve the overall value of the project to the users.

Three-phased process

The JIP has been progressed in three phases, the third and last of which is now under way. At the end of the second phase there was a workshop in late June which reviewed findings and learnings to date. A sister activity to the JIP will be the inaugural meeting of the International Compressor Users Forum on 29 September at the London Hilton Hotel on Park Lane, London, with the title 'Regain Performance to Recover Production'. [For details please contact e: **nicole.france@mse.co.uk** or T: +44 (0)20 8773 4500.]

The initial phase of the JIP involved collecting operating data from some 50 compressors, constructing a database to enable the machines to be benchmarked and conducting an initial performance analysis. MSE quantified head and efficiency losses and produced initial population trends. This first phase produced a substantial database about the operational performance of the 50-plus compressors and their attendant gas turbine or electric motor drivers. Head and efficiency losses were quantified and comparisons graphed. Similarly, a series of initial population trends were established and data graphed comparing:

- back-to-back configuration against

straight through;
- head per impeller against average head loss; and
- impeller tip speed against head loss.

This work established that there was:
- up to 25% head loss and efficiency loss (compared with manufacturers' data);
- discrepancy between the power absorbed and power delivered; and
- certain compressor designs may be more susceptible to performance loss than others.

This led into the second phase of the JIP where the objectives were:
- the identification and quantification of performance loss mechanisms; and
- the effects of design and selection of equipment, process, and operation and application.

In addition, this phase sought to establish cause and effect relationships, and to link to design groups.

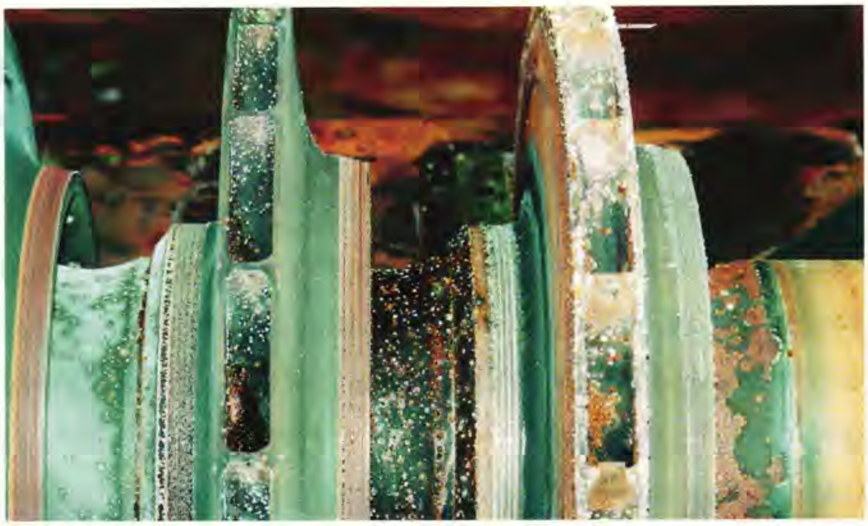
The work done by MSE showed the effects of four key performance loss mechanisms, the way that sensible design decisions can lead to performance retention and showed the way that even minimal liquid carry-over leads to sustained performance loss.

Online access

The completion of the database system using secure access means that each JIP member can view, online via a secure password, the performance of their own machines and how they compare, in detail, with various trends exhibited by anonymous data from the other members of the JIP.

Development of software was done in parallel with the data analysis work. New additions were made to the JIP tools, including the provision of knock-out drum calculations and a maintenance module. According to Dr Akhtar, the increasing use of the JIP tools is attracting widening interest in the industry, with existing participants in the JIP adding additional compressors to the database and new companies keen to join the JIP and provide data about compressors from around the world.

He noted that the main feature of JIP online was that it was very easy to use, being accessed via the Internet. Security aspects had been a key consideration in its design. These concerns were met by secure log in codes and a database that was hidden from the browser. The program-controlled access to the details of individual compressor trains meant that to an authorised user performance data on all the compressors was visible, but the identification of a particular company's compressor data was only visible to that company.



Fouled and corroded centrifugal compressor impellers

An individual company is able to access:
- design data details;
- performance maps;
- operating data in detail;
- summary data;
- trend graphs;
- performance loss adjustments; and
- maintenance records.

But in addition to this, users can access the wider compressor population to conduct specific searches on data and to build their own graphs and data to back up business and operating decisions.

Key mechanisms

According to MSE, although there are numerous performance loss mechanisms the JIP analyses have concentrated on the four key mechanisms:
- fouling involving deposition on impellers and diffuser passages;
- labyrinth seal wear;
- balance piston and centre-seal leakage; and
- liquid carry-over.

Each of these mechanisms has the potential to affect both head and efficiency, although in practise loss of efficiency is likely to involve a combination of some or all of these mechanisms.

Performance loss will manifest itself as an increase in power demand and a rise in temperature, but will always necessitate a speed increase to maintain production. However, performance loss will also involve a loss in production if the turbine driver is operating at or close to its EGT (exhaust gas temperature) limit or the compressor is at or near maximum speed (which is often the case).

Optimum compressor design

Dr Akhtar explained that for a given set of process conditions there can be numerous compressor design solutions. These will involve permutations of the diameters and number of impellers, and the operating speed to provide a particular head. Although there are many options open to vendors both performance and stability will vary. Correct selection is a key part of compressor optimisation and an area the JIP will provide new data input to. He also noted that effective compressor optimisation is also the key to performance retention. There is a generic relationship between flow coefficient and efficiency, which is fixed at the design stage. Optimal selection will then achieve the greatest performance stability in operation.

According to Dr Akhtar the evidence collected from the JIP so far suggests that susceptibility to fouling (deposition) and leakage is largely determined by the aspect ratio (volume flow to diameter) of the impellers, which is generally expressed as the flow coefficient.

Final phase

Following a successful workshop on 24 June and the feedback that produced, the final phase of the JIP will link performance loss mechanisms to compressor design attributes and produce a set of design guidelines for member operators. It will conclude with a workshop, following a seminar for compressor users entitled 'Regain Performance to Recover Production', which is also open to non-JIP members.

Asked whether the basic principles of the JIP – secure database, internet access – could be applied to other areas that required benchmarking Dr Akhtar indicated that he thought the principles and the sort of analysis that had been done in the current JIP could be more widely applied. Asked if MSE's other main area of expertise – gas turbine drivers in the oil and gas industry – might be a candidate, he simply smiled.

US energy security in the 21st century

Four major themes will dominate US energy security in the 21st century. One is the need to diversify the fuel mix (ie, oil, natural gas, coal, nuclear power, hydro-electricity and renewable resources). Another is the need to diversify the geographic origin of the energy. A third is conservation and energy efficiency. And the final theme is devising new ways of managing dependence on oil imports rather than aiming at achieving 'energy independence', writes *Dr Mamdouh G Salameh*.*

The US has for some time been diversifying its fuel mix and its energy import sources. First coal replaced the fuel wood, only to be itself replaced, to a large measure, by oil and then by natural gas. Natural gas and nuclear energy have been replacing coal and oil for electricity generation for years. In the future fuel-cell vehicles will make their appearance on the market side by side with internal combustion (IC) vehicles, while solar energy will contribute significantly to electricity generation along with natural gas and nuclear energy.

At present, US demand for energy is mainly met by fossil fuels. Indeed, in 2002 fossil fuels accounted for 89% of total US primary energy needs. Oil provided 39% of the total, with natural gas accounting for 26% and coal for 24%. Nuclear power provided 8% of energy needs and hydro-electricity nearly 3%.[1] The US will continue for the foreseeable future to be a major consumer of fossil fuels, with natural gas being the fastest growing fuel followed by oil and coal (see **Table 1**).

Oil dependency versus vulnerability

In the aftermath of the first oil crisis in 1973, the US and other major oil consuming countries have encouraged exploration for oil in areas outside the Middle East. Since then, exploration and development operations have accelerated all over the world, including the North Sea, West Africa, Latin America and, more recently, the Caspian Basin.

However, despite the increasing supplies from the North Sea, Latin America, West Africa and the Caspian Basin, the Arab Gulf region remains the main source for global oil supplies. This situation is underpinned by four facts. First, the Gulf region holds 65% of the global oil reserves and 35% of the world's total natural gas reserves.[2] Secondly, the Gulf region has at present 75%, or 4mn b/d, of the global spare oil production capacity.[3] Thirdly, costs of oil production in the Gulf region are the cheapest in the world, ranging from $1/b to $3/b. Finally, oil fields in the Gulf are located close to global markets and also to transport routes.

Dependence on oil imports by the US and other major consuming countries has been on the rise over the last two decades – a trend that is set to continue for the foreseeable future (see **Table 2**).

Promising provinces

Today, one promising oil province that remains unexplored is the Spratly Islands in the South China Sea, where exploration has been delayed by conflicting claims to the islands by six different countries. Potential reserves in the disputed territories are estimated in multi-billion barrels of oil and gas. Although the South China Sea is an attractive prospect, there is little likelihood that it is another North Sea.[4] But even if the South China Sea oil reserves are proven, they could hardly quench China's thirst for oil, let alone enhance US energy security. By 2010, China will need to import 6.35mn b/d, or 76%, of its needs, and would have by then overtaken Japan to become the world's second largest oil importer after the US.[5]

Another promising oil province is the Caspian Sea. Fanciful estimates claiming that Caspian oil reserves could rival those of other sources have gone as far as to ascribe potential recoverable oil reserves of 200bn barrels to the area. However, according to the *BP 2003 Statistical Review of World Energy*, the Caspian Sea's proven reserves are at present estimated at 17.1bn barrels, or 1.6% of the world's total proven reserves. Apart from the limited size of the reserves, the area's oil is very costly to find, develop, produce and transport to world markets. Caspian Sea oil production of 2–3mn b/d by 2010 can be achieved only when oil prices exceed the $17/b–$18/b range. Oil prices will be the key factor in the expansion of Caspian Sea oil.[6]

The US already imports 1.12mn b/d from West Africa (Nigeria and Angola). However, both countries have a very limited potential to increase production and export capacities. At best, they may be able to increase exports to the US by 600,000 b/d to 1.8mn b/d by 2010.

Russia hopes to become the largest oil supplier to the US; yet it remains to be seen how big a supplier Russia can actually be. Whilst Soviet geologists had mapped the country's oil fields in great detail, they ignored cost considerations that are standard in Western surveys.

Fuel	1990	2000	2005	2010	2015	2020	Average annual % change 1990–2020
Oil (mn b/d)	17.0	19.8	21.2	22.7	24.3	25.8	1.7
Natural gas (tn cf)	19.1	23.1	25.2	28.0	31.6	34.7	2.7
Coal (mn toe)	482	565	629	657	671	690	1.5

Sources: US Energy Information Administration (EIA), International Energy Outlook 2002/BP Statistical Review of World Energy, June 2003

Table 1: US fossil fuel consumption, 1990–2020

Soviet reserve estimates offer no clue as to how much of the actual proven oil reserves can be extracted at a reasonable cost. Furthermore, many major Russian oil fields were left in disrepair by the ex-Soviet regime.[7] Russia is currently producing at full capacity, taking advantage of the high crude oil prices. It will, however, need multi-billion dollar investments and advanced western technology to be able to lift its production from the current (2002) 7.6mn b/d to 8.5mn b/d by 2010.[8]

In order to meet the growing US and global demand for oil, production capacity has to be expanded in major Gulf producers. It is estimated that adding a new 5mn b/d capacity by the big five producers in the Gulf by 2006 will necessitate an estimated investment of $31.2bn.[9] Without a relatively high oil price ranging from £25/b to $28/b, the Gulf producers would neither have the incentive nor the capital to expand capacity.

Thus, a clear distinction should be made between dependency on oil imports and vulnerability. Oil dependency does not necessarily mean that the US is vulnerable to oil supply disruptions. If the US oil imports come from many producers and one of them suddenly stopped exporting oil, this would have little impact on the US, even at a high rate of US dependency, unless that producer is Saudi Arabia. The US, for instance, imported 58% of its oil needs in 2002, but it did so from 60 different countries, no one of which accounted for more than 16% of the total. Concentration on a few suppliers, not dependency, would lead to vulnerability.[10]

An important favourable development shaping the issue of energy security has been the proliferation of oil-producing countries. Between 1978 and 1996, 22 new non-Opec countries began producing oil – an increase of more than 40%. With these changes over the last 15 years, the issue of energy security has become less clear-cut. Even though net importing countries are, and will remain, dependent on oil from the Arab Gulf, the magnitude of the threat seems smaller. However, concern over energy security will never go away, but each new supplier contributes to the perception of a diminishing threat.[11]

Year	US	W. Europe	Japan
1983	9%	41%	60%
1987	16%	43%	60%
1990	25%	48%	65%
1993	21%	50%	68%
1998	20%	50%	76%
2000	25%	57%	79%
2001	26%	57%	81%
2002	27%	58%	80%

Source: EIA/BP Statistical Review of World Energy, June 2003/*Japan's Ministry of International Trade & Industry (MITI)*

Table 2: Imports from the Gulf as % of net oil imports, 1983–2002

Oil import dependency reduction strategies

The lack of sufficient domestic oil resources and the absence of new oil discoveries mean that the US' dependence on oil imports can only deepen. This dependence has raised concerns regarding the nation's energy security. Various strategies have been devised to reduce US dependence on imported oil and a close examination of these strategies might indicate their prospects of success in the future.

The use of technology to enhance domestic oil production: A major ingredient of the Bush Administration's energy policy is the use of technological advances to expand domestic oil production in both onshore and offshore areas within the US. One such area is Alaska's Arctic National Wildlife Refuge (ANWR). With recoverable reserves estimated at 10bn barrels, ANWR's initial production is projected to reach 600,000 b/d, peaking at just over 1mn b/d by 2010.[12]

However, the American Council for an Energy-efficient Economy estimates that gradually raising the fuel efficiency of light trucks and cars in the US from the current 21.2 miles per gallon (mpg) to 35 mpg, would save 1.5mn b/d in 2010 and 4.5mn b/d by 2020 – up to seven times the 600,000 b/d ANWR could initially produce. Moreover, these could be permanent energy savings that would not require invading an environmentally preserved area.[13]

But, in spite of the potential to increase domestic production by relying on technological advances, three limiting factors do exist. The first factor is the volatility of the oil price. Despite a substantial cost reduction, it is still cheaper to produce oil outside rather than inside the US. Thus, high oil prices will make it cost-effective to explore for oil in areas like ANWR and low oil prices are likely to discourage production. The second factor is that advances in technology have not yet managed to arrest the ongoing decline in US oil production. Finally, most of these untapped oil resources are located in environmentally sensitive areas. Opposition by the environmental lobby could still scupper oil exploration in these areas.

Acceleration of renewable energy research: The US is already investing heavily in research into solar photovoltaic, fuel-cell motor technology and other technologies for alternative and renewable energy sources. Solar and hydrogen are destined to become major energy sources during the 21st century, but only if their enabling technologies improve significantly enough to ensure affordability and convenience of use.

In 2001, renewable energy sources contributed 1% to the global primary energy demand. However, by 2025 they are projected to contribute 6%, rising to 13% by 2050. For the US, the contribution of renewable energy to its primary energy needs is projected to reach 2% by 2025, rising to 3% by 2050 (see **Table 3**).

The photovoltaic cell is, at present, the object of a great deal of research and investment but significant advances

	2001		2025		2050	
	World	US	World	US	World	US
Primary Energy	9,128	2,237	16,194	3,419	18,697	4,403
Oil	3,511	896	5,135	1,267	5,338	1,663
Natural Gas	2,164	555	5,119	1,043	6,927	1,663
Coal	2,255	556	3,526	719	2,748	552
Nuclear	601	183	1,061	300	955	375
Hydro	505	44	314	20	299	18
Renewables	92	3	1,039	70	2,430	132
Renewables: % of total	1.0%	0.1%	6%	2%	13%	3%

Sources: Shell International, Scenarios to 2050/BP Statistical Review of World Energy, June 2003/*author's projections*

Table 3: Global primary energy consumption, 2001–2050 (mn toe)

in the storage of electricity and a reduction in costs must be made before solar generation comes into its own.

Hydrogen-powered fuel cells will, in the future, supply an increasing percentage of commercial and residential electricity. But it is in transport that fuel-cell motor technology will eventually leave its mark on future energy needs. However, it will take at least 15–20 years before fuel-cell cars dominate the highways and certainly not before they are able to compete with today's cars in terms of range, convenience and affordability.

Conservation: The US consumes more energy than the size of its economy or its share of the world population would warrant. It accounts for 22% of the global GDP but uses 25% of the world's energy and, in doing so, accounts for 25% of global emissions of carbon dioxide. By contrast, the European Union accounts for 20% of the global GDP but only consumes 16% of the world's energy. The numbers for Japan are similar. What these figures boil down to is that for every dollar's worth of goods and services the US produces, it consumes 40% more energy than other industrialised nations.[14]

The fact is that if, from an energy policy perspective, the US economy operated as efficiently as those of Europe or Japan, American energy consumption would fall by about 30%. In that case US carbon emissions might be expected to fall to the European rate per dollar of GDP; that would mean a 35% drop. This means that the US would meet the Kyoto emission targets – to be 7% below its 1990 carbon dioxide emissions by 2012.

However, conservation alone is not the answer to the US' energy difficulties. But conservation and energy efficiency combined can easily help reduce energy consumption by an estimated 30% and carbon emissions by 35%.

Nuclear power: Nuclear energy provides the second largest source of energy for US electricity generation. In 2002 coal provided 56% of electricity generation, while nuclear energy provided 20%, followed by natural gas 18%. The rest was provided by hydropower, oil and renewable sources.

The EIA estimates that US demand for electricity will rise by 45% over the next 20 years. With US electricity demand rising so fast, the EIA is projecting that the country will need to build 1,300 new generating plants in the next 20 years – almost one plant every two weeks. However, efficiency measures alone could obviate the need for building 610 of the 1,300 plants needed.[15]

Though not strictly renewable, nuclear power is one of the cleanest energy sources. Nuclear power produces no atmospheric pollution. Nevertheless, the public perception of nuclear power is still negative. Hanging over it is the question of radioactive waste and how to dispose of it safely. Nuclear power must, however, expand before 2020 to help supply the increasing world demand for electricity.

North American regional energy policy: The pursuance of a Hemispheric energy policy involving Canada and Mexico has always been considered a cornerstone in ensuring US energy security and reducing dependence on oil imports from the Arab Gulf region. Indeed, both countries have been major suppliers of oil to the US for the last several years. In 2002, Mexico exported 1.53mn b/d of oil to the US, with Canada exporting another 1.94mn b/d of crude and refined products.[16]

The energy interdependence between the three North American states is even stronger in natural gas than in oil. Canada has been supplying the bulk of US natural gas imports and is expected to continue to do so for the foreseeable future. In 2002, Canada supplied 16% of US gas needs.[17]

Within five years, oil flowing south from Alberta's oil sands is expected to surpass the current output of 1mn b/d from Alaska'a North Slope. By 2015, some 75% of Canada's projected oil sands production of 1.6mn b/d will go down to the US.[18]

The energy trade between the US and Mexico has substantially expanded in the last several years. In 2002, the US supplied Mexico with 18% of its gas needs and 14% of its petroleum products, in return it imported 8% of its crude oil needs. For the foreseeable future Mexico is likely to remain a net gas importer.[19]

Mexico needs to invest billions of dollars to upgrade and modernise its oil and gas infrastructure. State-run Pemex has neither the capital nor the technology to extract the amount of gas Mexico desperately needs. According to Pemex, Mexican oil output will decline by 33% within the next five years unless investments of $33bn are made in oil and gas exploration. Therefore, there is no substitute to opening the door to private and foreign investments. This means that the Mexican constitution must be amended to allow foreign participation in energy production.

Mexico's future as an oil exporter depends on the success of the ongoing remedial work on its offshore Gulf of Mexico Cantarell fields, which contain the country's largest known oil reserves and traditionally have provided some 75% of total national oil production. In 1996 well productivity plummeted, in some cases to one-fourth of previous levels, signalling a dramatic decline in reservoir pressure. Now, after more than two years of nitrogen injection, the Cantarell pressure has stabilised according to Pemex. The company hopes to raise its offshore production from the current 2.7mn b/d to 3.2mn b/d by 2006.[20]

Turning to Hemispheric sources of oil to reduce the US vulnerability to oil crises can't guarantee US energy security. Mexico and Canada have limited oil production and export capacities and can't, therefore, satisfy US growing oil needs in the long-term. The combined oil export capacity of both countries could at best be increased from the current 3.4mn b/d to 4mn b/d by 2010. However, some experts have considerable doubts about Mexico's ability to maintain its oil exports even at current levels because of stagnating production and accelerating domestic consumption.

Facing the future

Fossil fuels, particularly crude oil and natural gas, will continue to dominate the US energy needs well into the 21st century. And, while recent technological advances have made it possible to economically produce oil from conventional and unconventional sources, they have not yet arrested the ongoing decline in US oil production. Technology cannot make up for declining resources. Furthermore, despite the huge investment in renewable energy sources like fuel-cell motor technology and solar photovoltaic, their contribution to US primary energy needs will still be measured in single percentage points even by 2050.

Pursuing a Hemispheric energy policy will not guarantee energy security. Mexico and Canada have limited oil production and export capacities and cannot, therefore, satisfy US growing oil needs in the long-term. Despite increasing supplies from the North Sea, Latin America, West Africa and the projected contribution of the Caspian Basin to global energy security, the Arab Gulf region will continue to occupy the driver's seat in the global oil market both at present and for the foreseeable future. Any new American oil ventures outside the Arab Gulf will reshape the oil market only at the margin.

The US should, therefore, realise that oil security does not mean achieving a state of self-sufficiency. Nor does dependency on oil imports necessarily mean vulnerability to supply disruptions. US energy security could be better served by devising ways of managing dependence rather than engaging in meaningless debate over energy independence. This means that the US should take a fresh look at its sanctions policy against major oil producers like Iran and Libya. Such a policy is detrimental to US energy security in the sense that it hampers the diversification and expansion of the global oil production capacity and also increases the risk of oil supply disruptions.

**Dr Mamdouh G Salameh is an international oil economist, a consultant to the World Bank in Washington DC, and a technical expert of the United Nations Industrial Development Organization (UNIDO) in Vienna. He is Director of the Oil Market Consultancy Service in the UK and a member of the International Institute for Strategic Studies (IISS) in London and the Royal Institute of International Affairs. This article is a revised and shortened version of the paper that was presented at the 2002 USAEE/IAEE North American Conference in Vancouver, Canada, on 6–8 October, 2002.*

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Inspection and Testing of Electrical Installations at Petrol Filling Stations

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Tri-lateral drilling on Troll

Andy Cuthbert, Operations Leader – Multilateral Projects, Sperry-Sun, *Jofrid Hegreberg*, Senior Drilling Engineer at Norsk Hydro and *Elisabeth Skoglund*, Senior Reservoir Engineer, Norsk Hydro **outline how dual lateral ITBS™ (Isolated Tie-Back System) technology was recently enhanced to increase the total drainage area of a low permeability mica-sand reservoir from the existing sub-sea template structures within the North Sea Troll field, where production levels are low. The addition of a second lateral leg was created by incorporating two ITBS™ to produce a trilateral well, X-13.**

The Troll oil field is located approximately 80 km north-west of Bergen, on the Norwegian Continental Shelf. The field produces up to 445,000 b/d, making it the largest producing oil field in the North Sea at present and accounting for more than 13% of Norway's production. The Troll West gas province (TWGP), where X-13 is located, has an oil column approximately 11–13 metres thick. The combined Troll development is expected to recover some 1.33bn barrels of oil.

Dual lateral ITBS™ (Isolated Tie-Back System) technology was recently enhanced to increase the total drainage area of a low permeability mica-sand reservoir from the existing sub-sea template structures within the Troll field, where production levels are low. The addition of a second lateral leg was created by incorporating two ITBS™ to produce a trilateral well, X-13.

Two 9 $^5/_8$-inch liner joints incorporating pre-milled windows and pre-installed latch couplings were installed a specific distance apart, aligned to the same orientation. Once the liner had been cemented into place and the mainbore drilled and lined with screens, a drilling whipstock was latched into the lower coupling and the lower window opened up. When drilling of this branch was complete, the whipstock was retrieved and replaced by a deflector. The deflector stung into the mainbore screens over which a flexible junction with a D-section leg and mainbore stinger were installed to create the junction. The flexible junction was oriented to enable the stinger to land in a seal stack in the deflector, thereby creating the means of communication with the mainbore. The D-section was attached to the lateral screens. Drilling out and completion of the upper lateral was essentially a duplication of the lower lateral.

By June 2003, a total of 26 TAML Level 5 ITBS™ Sperry-Sun multilateral junctions had been completed on the Troll oil field.

Planning stage

A number of project objectives needed to be met. In the planning stage these can be summarised as:

- Complete the installation within a time target of seven days.
- Increase production.
- Make use of hydraulic and mechanical seals for junction isolation to prevent potential sand production.
- Avoid steel milling while using a simple and robust installation process.
- Optimise available flow areas.
- Ensure access to both mainbore and lateral leg.
- Preserve the ability to plug either the mainbore or the lateral above the junction.

Window placement considerations and limitations: In order to provide two exits, the existing ITBS™ technology was modified by incorporating two pre-milled, aluminium-wrapped 9 $^5/_8$-inch window joints as components of a tapered 10 $^3/_4$-inch x 9 $^5/_8$-inch liner string. A drillable alignment bushing (a 60-cm slotted aluminium sleeve) was incorporated into the window joint and aligned to the window. The orienting key sub of the inner string engaged the slot and aligned the inner string to the direction of the window. The key sub itself was aligned to a MWD (measuring while drilling) tool below it; and, by this means, the window orientation was determined. The internal diameter of the drillable bushing, however, was 7.25-inches – therefore, only one bushing below the lower window could be used.

The spacing between the pre-milled windows in the 9 $^5/_8$-inch liner joints was governed by the requirement that the distance between the lateral wells at the minimum closest approach be 2 metres. To meet this requirement, the distance between the upper and lower windows had to be a minimum of 84 metres.

The reservoir sands can comprise heavily calcified layers, but stringer-free formation was preferred in the vicinity of the window areas to facilitate the milling process and, subsequently, the lateral drilling. A 15-metre stringer-free area around the window exit was stipulated. When a candidate area had been identified for the upper window, a suitable area for the lower window had to be identified at the minimum distance specified.

Only one 10 $^3/_4$-inch crossover could be accommodated in the liner string, and this crossover had to be placed above the upper window. The crossover consisted of a 10 $^3/_4$-inch joint with a 9 $^5/_8$-inch inner joint with a muleshoe leading edge and an 11-metre long highside slot. The slot aligned the flexible junction by means of an orienting key that engages the slot. Without the assistance of this alignment slot to guide the lower flexible junction, orientation would have to have been achieved by means of a MWD tool alone.

Optimal field drainage required that the longest branch be drilled to the south of the mainbore, ie exiting the mainbore to the right. The lower branch was to be drilled to the north, therefore exiting the mainbore to the left.

Factors associated with the final window design included:

- Capability to implement the maximum allowable dogleg to achieve desired lateral well paths.
- Ability to accurately align the upper and lower windows.
- Capability to implement any desired well path direction and length.
- Option to swap lateral well bore direction.
- To avoid the possible introduction of error while landing the windows, it was decided to orientate both windows as near to highside as possible. It was necessary to align the upper window as closely as possible to the lower widow orientation. Any estimated cumulative error might place the upper window at 20° left or right of highside, which would be acceptable. It was therefore of great importance to achieve an accurate highside orientation of the lower window during installation.
- Had cumulative error placed the upper window beyond 20° left of highside a contingency plan was drawn up to be able to swap the direction of the lateral bores to change targets.

Operations stage

Drilling and landing the 12 $^{1}/_{4}$-inch/13 1/2-inch section: After the 13 $^{3}/_{8}$-inch casing had been set, the 12 $^{1}/_{4}$-inch hole was drilled and simultaneously under-reamed to 13 $^{1}/_{2}$-inches while building angle to horizontal in the reservoir. A 15-metre stringer-free area was identified from the surface logs at the desired depth, and the well was drilled to TD (total depth).

Running liner with pre-milled ITBS™ windows – Phase 1: The upper window was aligned to the lower window, and the inner string was run and engaged in the drillable alignment bushing. The liner string could now be rotated, and a lower window orientation of 3° right of highside was obtained. The liner hanger was set and the liner cemented in place in the same trip before retrieving the inner string.

An MWD verification assembly recorded an orientation of 7° left of highside for the upper window placement, confirming that a relatively accurate alignment between the windows had been achieved.

Drilling and completing the 8 $^{1}/_{2}$-inch mainbore section: The 8 $^{1}/_{2}$-inch mainbore section was drilled horizontally using a rotary steerable system. The mainbore section was completed with a dual string of 6 $^{5}/_{8}$-inch and 5 $^{1}/_{2}$-inch screens, which were landed using a setting sleeve and PBR (polished bore receptacle). No hanger or packer was required at this stage.

Whipstock installation and 8 $^{1}/_{2}$-inch lower lateral drilling – Phase 2: The second phase of the operation was to install the lower drilling whipstock and mill out the aluminium window sleeve in preparation for drilling the lower lateral. After a clean-up run, the whipstock was run bolted to the window mill. The whipstock was installed and oriented toward the window by engaging into the lower 9 $^{5}/_{8}$-inch latch coupling. The mills were sheared free of the whipstock, and the aluminium sleeve was milled to open the lower window exit. After pulling out with the milling assembly, the lower lateral bore was drilled with a rotary steerable system. The lateral left was opened, ready to receive the sand screens and the lower ITBS™ flexible junction assembly.

Lower lateral reservoir section, completion – Phase 3: The third phase of the installation consisted of four sub-operations:

1) Retrieval of the ITBS™ drilling whipstock by using a conventional fishing spear deployed and inserted in the hollow bore of the whipstock. The whipstock was simply pulled free of the coupling and recovered to surface.

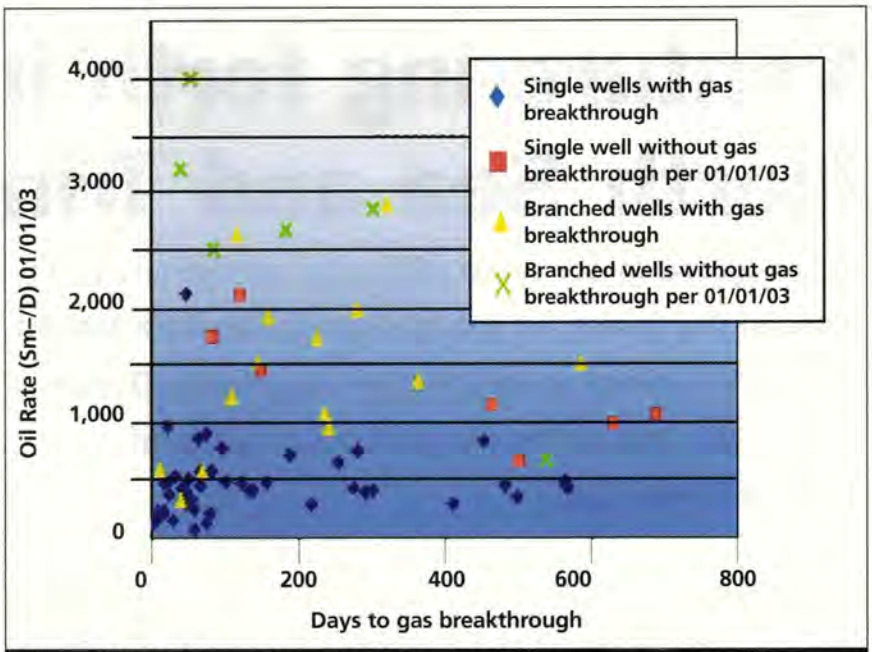

Figure 1: Oil rate compared to gas breakthrough on Troll oil wells

2) Washing and brushing both latch coupling areas with a junk basket/brush assembly prior to the lower deflector installation.

3) Installing the lower ITBS™ deflector and seal stem assembly. The deflector was aligned to the window in a similar fashion to the whipstock, and the seal stem created the conduit to the mainbore by stinging into the PBR. The well was considered to be in a prepared condition to receive the sand screens for the lower lateral.

4) Installing the ITBS™ flexible junction together with a dual string of 6 $^{5}/_{8}$-inch and 5 $^{1}/_{2}$-inch screens. The operation took place without the mechanical aid of the slot guide as there was no 10 $^{3}/_{4}$-inch x 9 $^{5}/_{8}$-inch alignment crossover. The screens and lower flexible junction were landed successfully and, by simultaneously stinging into the deflector, created a common flow path between the mainbore and lateral section. The running tool was released to leave a PBR ready to receive the upper deflector seal stem assembly.

Upper lateral reservoir section – Phase 4: The fourth phase in the trilateral operation was to install the upper drilling whipstock and mill out the aluminium window. The whipstock was run in a similar fashion to the lower whipstock installation. After pulling out with the milling assembly, the upper lateral bore was drilled with a rotary steerable system with the lateral left open, ready to receive the sand screens and the upper flexible junction assembly.

Upper lateral reservoir section, completion – Phase 5: The fifth phase of the trilateral installation consisted of four sub-operations similar to those of Phase 3 – namely retrieval of the drilling whipstock, clean-up of the upper latch coupling area, installation of the deflector and seal stem assembly which stings in to the PBR above the lower flexible junction assembly, and the installation of the flexible junction and upper lateral screens.

The upper flexible junction was landed successfully and the running tool released to leave a PBR (no hanger or packer) ready to receive the middle completion.

A middle completion was installed by stinging into the PBR above the flexible junction.

Production increase

Total time attributed to this ITBS™ installation, calculated by Norsk Hydro, amounted to 7.2 days. Excluding lost time, the direct ITBS™ operations were completed in 5 days; associated operations were completed in 2.1 days and lost time amounted to 4 hours.

The X-13 well currently produces 22,000 b/d from a production screen section of 7,450 metres. The draw down of 0.25 bars is lower than that found in traditional horizontal wells, delaying gas break-through (see **Figure 1**). This well alone will add some 1.5mn barrels of oil to total Troll oil production in a shorter space of time.

Development of Troll oil as a whole will involve the drilling of at least 44 multilateral wells, including six three-branched wells and a four-branched well, contributing to additional reserves in the region of 100mn barrels of oil.

Venture-ing forth in the North Sea and Trinidad

In the second of our series of feature articles analysing some of the smaller oil and gas companies from around the world – based on information supplied by *Online-Data – we take a closer look at the activities of *Venture Production.***

Founded in 1996, Venture Production is a public independent oil and gas production company headquartered in Aberdeen. Its two geographic areas of focus are the UK sector of the North Sea and Trinidad (see **Figures 1** and **2**).

Venture's strategy is focused on the acquisition and exploitation of proven reserves and the development of discovered but undeveloped resources, that are collectively known as 'stranded' reserves. The company's business model is based on adding value to these stranded reserves through the application of modern technology and operating practices together with a change in management philosophy. In order to add value, Venture normally seeks to take large working interest positions and act as operator.

Venture believes its business model ideally positions it to capitalise on change in the oil and gas industry in mature provinces such as the North Sea. It has established a track record of releasing the stranded reserve potential on assets in its two geographical areas of focus – the North Sea and Trinidad – where a series of field rejuvenation programmes has led to increased production, longer field life and increased reserves.

Highlights in 2002

During 2002 Venture continued its rapid growth, with average production rising from 4,868 boe/d in 2001 to 8,681 boe/d. This increase in production combined with favourable oil prices led to a record financial performance (see **Table 1**). During the year, Venture completed three new acquisitions in the North Sea and in March gained a full listing on the London Stock Exchange, raising £32.5mn (£29.5mn net) in new equity.

In May 2002, the company gained DTI approval for the development of the Sycamore field on block 16/12a in the North Sea (see **Figure 2**). Sycamore, which was identified as a result of a major geological study carried out by Venture, has been developed on a fast-track programme utilising the existing 'Trees' fields subsea infrastructure.

Meanwhile, in Trinidad, activity was focused on the offshore drilling campaign in the Brighton Marine and Point Ligoure fields, where a total of 10 new wells were drilled to develop the Brighton Marine field and satisfy Venture's minimum work obligations in appraising the Point Ligoure field. The results of these wells indicate that there is further development potential in the northern part of the Point Ligoure block and the southern part of the Brighton Marine field, both of which are currently being evaluated.

Reserves and acquisition

In 2002 Venture's total proven and probable oil and gas reserves increased to 49.7mn boe from 39.0mn boe, with oil representing 68% of this total. By geography, the company's reserves are split 90% in the UK and 10% in Trinidad.

Proven and probable reserves are expected to rise to 75.9mn boe after the company entered into an agreement in August 2003 to acquire First Oil's interests in the Audrey, Ann and Alison producing gas fields in the southern North Sea. Venture is already

	2002	2001	% Increase
Production (boe/d)	8,681	4,868	78
Average price per boe ($)	23.55	20.53	15
Turnover (£mn)	52.7	25.2	109
Gross profit (£mn)	18.3	6.9	165
Operating profit (£mn)	14.3	4.0	258
Profit after tax (£mn)	7.2	0.9	700
Operating cashflow (£mn)	35.1	5.0	602

Table 1: Key statistics

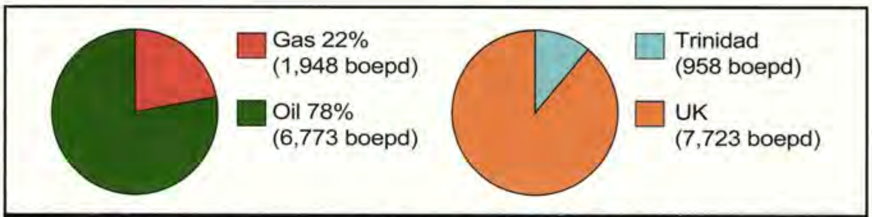

Figure 1: Venture's oil and gas production in boe/d, and by location

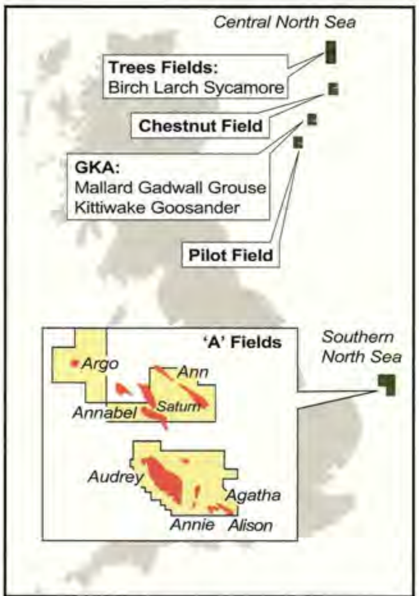

Figure 2: UK interests

operator of each of these fields, the acquisition providing it with 100% interest and further upside from its planned development of these gas producing assets and their associated near-field satellite prospects.

As a result of acquisitions, Venture's net production in 4Q2003 is expected to rise by an average of 7,000 boe/d. The company has also confirmed that, jointly with Dana Petroleum, it has been awarded the licences to develop four blocks adjacent to the Greater Kittiwake Area (GKA). These blocks contain a number of undeveloped discoveries and Venture will become operator of the entire GKA area upon completion of the acquisition from Shell and ExxonMobil. The acquisition, announced in April 2003, is expected to complete in 4Q2003.

Venture also recently entered into an agreement to acquire ConocoPhillips' 30.78% unitised interest in the Audrey gas producing field that spans blocks 48/15a and 49/11a, and is expected to become field operator in due course. ●

Visit Venture Production's website at www.vpc.co.uk **or**
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F: +44 (0)1224 658151

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Some changes for the future

Dr John Brooks, a member of the IP Council, recently posed a number of questions about the future membership structure of the Energy Institute (EI) to Professional Affairs Director Sarah Beacock.

Q: How does the EI membership structure impact upon those like me who were members of the Institute of Petroleum (IP)?

A: Anyone who became a member of the Institute of Petroleum will retain their current grade of membership in the EI; only the designations have changed. Thus FInstPet becomes FEI, MInstPet becomes MEI and SInstPet becomes Student Member. No further election procedure is required.

Q: The IP always offered a membership service – what is the difference for a chartered professional body such as the EI?

A: One of the benefits of becoming a qualifying body recognised by Royal Charter is that the award of designatory titles represents a level of professional recognition for the holder which is widely understood. It denotes that a robust and consistent set of standards has been applied in assessing those achieving Fellow (FEI), Member (MEI), Associate Member (AMEI), Technician Member (TMEI) and Graduate Member (GradEI) status. The award of the four professional grades of FEI, MEI, AMEI and TMEI signify the achievement of a level of seniority and expertise determined by a person's role and experience in the energy sector.

Another feature of being a chartered professional body is that certain standards and benchmarks must apply – these are often recognised by other public and private organisations, from government departments to insurance companies, depending upon their own requirements. It is not enough simply to show an interest in energy. Applying for professional recognition means meeting given criteria and demonstrating your competence in, and commitment to, your chosen field of work and your own role in it.

Q: What about those who have an interest in energy, or just one aspect of it – does this mean they cannot be members?

A: No, not at all. It is recognised that many people who work on the fringes of the energy community may not want, or need, professional recognition. They may already be professionally recognised in their main job role – for example, lawyers, accountants – or they may simply require access to the many other membership benefits that the EI offers. In particular, the EI's strong technical, scientific and learned society activities prove a major draw to those who want to have access to the vast energy-related resources that the EI holds. Other advantages include the networking opportunities and discounted rates for training courses and events.

For those who wish to acquire these benefits of membership but who do not wish to have professional recognition there is the grade of Affiliate. Being an Affiliate has the advantage of instant access to many benefits – simply complete a brief application, pay your first year's subscription and receive a welcome pack – without the need to go through a formal election process. In addition, all Affiliates who would like to consider a future move to a professionally recognised grade of membership will be given advice and guidance on how to achieve it.

Q: I've heard that some people think the EI will just be for engineers in the future. What about other energy professionals?

A: Whilst both the IP and Institute of Energy (InstE) had a large percentage of engineers amongst their memberships, both also had members from a wide range of disciplines and sectors. The EI's membership will continue to include industrialists, strategists, scientists, engineers, researchers, policymakers, academics, economists, public servants, consultants and many more people from all energy sectors, including the exploration for and extraction of fuel sources, the generation and distribution of energy, the efficiency of energy use and its conservation, as well as the development of future energy supplies. A healthy professional body encourages diversity.

Q: What about those who are only just starting out in their career?

A: The grade of Graduate, whilst not a full professional grade, attests to the fact that the individual is at a very early stage of their career and holds a qualification that can ultimately lead to full professional recognition at one of the four professional grades.

Q: How will we attract new blood into the energy industry?

A: As well as supporting Graduate Members at an early stage of their career the EI will encourage students on energy-related courses to join. Again, the grade of Student does not carry professional recognition as students are quite clearly at the first stage of a future career that will, we hope, eventually lead to their recognition as an energy professional. However, membership does grant students access to all the other benefits that full members have, including advice on future careers, access to potential employers and guidance towards professional recognition. The EI is committed to the future of its youngest members, and in aiding them to prepare for careers addressing the world's energy challenges.

Q: Where will future members of the EI originate from?

A: We hope that existing members will continue to be a fruitful source of recruitment of new members. This helps to strengthen the depth and diversity of the membership to confirm the EI's position as the pre-eminent professional body for those in all sectors of the energy industry. Where the members come from, in terms of the differing sectors, is often mirrored by the changes in the energy community – be they reorganisations, diversification of businesses, new markets establishing or other changes that influence the structure of energy businesses globally. We watch these major trends to determine the best forms of promotion, recruitment and service support. Ultimately, the EI exists for the public benefit, so any member of the pubic may join if they have an interest in the subject.

Q: How can existing members help?

A: To be able to promote membership effectively it is important to understand how members qualify for professional recognition. The table opposite shows the typical requirements to qualify for Fellow, Member, Associate Member and Technician Member. Additionally, of course, the EI will undertake regular promotions and campaigns to encourage new members to join.

The typical requirements for each grade of membership are as follows:	Minimum qualifications	Minimum training and experience
Fellow (FEI)	*Honours Degree or assessed equivalent	5 years' experience in a position of superior responsibility in an energy-related role
Member (MEI)	*Honours Degree or assessed equivalent	2 years' structured training or equivalent in an energy field. Further 2 years' experience at a responsible level in an energy-related role
Associate Member (AMEI)	*NVQ Level 4 in Managing Energy or HND/C or equivalent	2 years' structured training or equivalent in an energy field. Further 2 years' experience at a supervisory level in an energy-related role
Technician Member (TMEI)	*Advanced GNVQ, NC/D or equivalent	2 years' structured training or equivalent in an energy field. Further 2 years' experience in an energy-related role
Affiliate	N/A	N/A
Graduate (GradEI)	Energy-related programme of study leading to a qualification recognised for MEI, AMEI or TMEI	N/A
Student	Currently studying an energy-related academic or vocational course	N/A

In advising potential new members it is not always immediately easy to identify the appropriate grade of membership. It is always advisable for applicants to read the guidance notes for each grade, which are available on the website at **www.energyinst.org.uk** or contact the Membership Officers for advice. Applicants submitting a CV to **membership@energyinst.org.uk** will receive personalised advice on the most suitable grade for them.

Q: **This sounds rather a lengthy process – isn't there a quicker method?**
A: Yes, membership benefits can be accessed immediately by applying for the fast-track Affiliate grade. This gives the member time to complete the formal election procedure whilst still receiving membership benefits.

Q: **What about those with no formal qualifications – does this mean they cannot be professionally recognised?**
A: Certainly not! Those without formal qualifications often have valuable additional experience. For such applicants there is an alternative route to membership with professional recognition, which enables them to be equally recognised. More details on this route can be obtained from **membership@energyinst.org.uk**

Q: **How will the requirements for engineers differ from other professionally recognised members?**
A: There is no difference in the standards applied during the application process, but there are particular qualification and experience requirements for those wishing to register as engineers. Further advice can be gained from **membership@energyinst.org.uk**

Q: **Are there any benefits for those members who currently hold CEng, IEng or EngTech status?**
A: Yes. The Energy Institute is a licensed body of the Engineering Council (UK). A large number of members from both the IP and InstE are registered with the EC(UK) as either Chartered or Incorporated Engineers or Engineering Technicians. However, in the past only the InstE had been able to register engineers and technicians with the EC(UK) directly as an additional membership service. The EI now provides this service and members who are currently registered with the EC(UK) through another professional body can, if they wish, transfer their registration status to the EI. Individuals considering applying for CEng, IEng and EngTech can now apply directly through the EI.

Q: **What about the new Chartered titles? Does everyone who is currently a member automatically become Chartered?**
A: The EI is the only body in the world entitled to award the designatory titles 'Chartered Petroleum Engineer' and 'Chartered Energy Engineer'. The award of these titles, or indeed CEng, is not automatic; they are available to any suitably-qualified member on application and assessment against given criteria. In the future anyone applying for membership (or transferring to a higher grade of membership) will automatically be assessed as to their suitability for one of the designatory titles. However, for existing members for whom this facility has not previously been available, it will be possible to apply to be assessed for award of one of these titles.

For further information please contact **membership@energyinst.org.uk**

ip : / / awards / 2003

The announcement of nominees will be published in the October issue of *Petroleum Review*. They will also be posted on the IP Awards website **www.ipawards.com** by 15 September 2003.

To book a table for the ceremony at The Savoy, London, on the 20 November, please contact: Laura Viscione, T: +44 (0)20 7467 7174 e:**lviscione@energyinst.org.uk**

Subsea solution for Scandinavian pipeline

Statoil's Snøhvit gas extraction development in the Barents Sea is the first liquefied natural gas (LNG) project in Europe and the most northerly project of its kind in the world, writes *Ian Robinson*, Vice President, Sales & Marketing, Vector International. It will use gas produced from the Askeladd, Albatross and Snøhvit fields off the north coast of Norway.

Essential to the extraction of the large volumes of gas – the fields contain total reserves of at least 300bn cm of natural gas and up to 6.2mn barrels of condensate – will be large diameter piping, including a multiphase transportation pipeline carrying gas onshore. At 160 km, the multiphase pipeline will be the longest ever built on the Norwegian Continental Shelf.

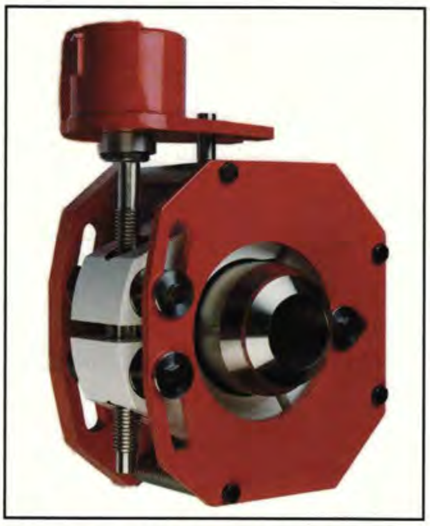
The Snøhvit development also involves construction of a subsea production system, including a number of seabed templates.

The solution

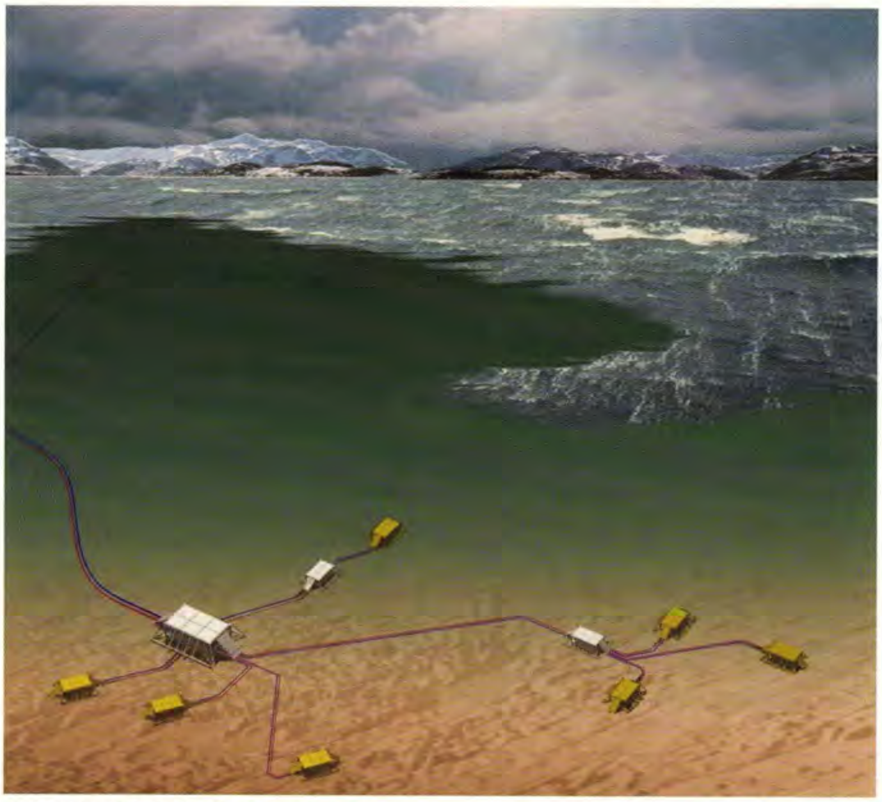
Vector International is providing subsea pipe connectors for the project – the largest it has built to date. The biggest connector for the project is a massive 28 inches in diameter and has a design life of some 30 years. Some 23 pipe connectors are being provided in sizes ranging from 14 to 28 inches in diameter. They are designed to operate at pressures of 3,000 psi and be able to withstand the harsh conditions of the region.

The technology

Vector's Optima subsea pipe connectors (see right) feature enhanced misalignment capabilities, meaning they can engage around a hub even with a misalignment of 5°. This guarantees first-time connection – a particularly valuable advantage for ROV (remotely operated vehicle) applications in difficult conditions. This is a feature incorporated specifically with diverless installations in mind – a key benefit for the Snøhvit project as much of the construction work is being carried out by subsea ROV installation.



Vector International's Optima subsea connector will be used on the subsea production system of Statoil's Snøhvit project in the North Sea



Schematic of Snøhvit subsea structure

Optima connectors also incorporate Vector's DuoSeal double-seal technology that provides both internal and external seal integrity – which can be qualified at the time of installation – preventing ingress of seawater and egress of piping content in high pressures and at depths up to and greater than 3,000 metres.

High-performance at such depths more than adequately meets the demands for the Snøhvit project for which Optimas will be used at depths of some 350 metres.

The Optima connectors also feature built-in protection against corrosion and are proven to work in a wide range of temperatures.

T: +44 (0)1639 822555
F: +44 (0)1639 822000
e: **info@vectorint.com**
www.vectorint.com

If you would like your new product releases to be considered for our *Technology News* pages, please send the relevant information and photos/graphics to:
Kim Jackson, Associate Editor, *Petroleum Review*,
61 New Cavendish Street, London W1G 7AR, UK
or e: petrev@energyinst.org.uk

Membership News

NEW MEMBERS

Dr H Al-Rabiah, Leeds
Mr D F Boran, Lloyds TSB Bank
Ms C I Bryant, Oakwood Environmental
Dr L Darrell, Leeds
Mr W J Davies, Wirral
Mr K M Gale, Defence Fuels Group
Mr A P Jenkins, Oakwood Environmental
Mr G Jones, Mold
Mr R I Makun, SNEPCO
Lt Commander W F McCord KSJ, Paisley
Mr S W McShannon, Aberdeen
Mr A O Ogbomo, Octopus Systems Worldwide
Mr K Parkin, Ellesmere Port
Mr P S Raju, India
Mr P S Swain, London
Mr A M Udoroh, Nigeria

STUDENTS

Mr C V E Ivuerah, London
Mr O U Obirieze, Nottingham
Mr A Olaoya, University of Newcastle-upon-Tyne

NEW FELLOW

Mr R A Simpson FEI

After serving in the Royal Navy Engineering Branch, Bob joined The Trinidad Oil Company in 1957. Following the takeover by Texaco he transferred to marketing and held various positions in the West Indies and Bahamas. In 1973 he joined Aviation Fuel Services at Heathrow Airport and the IP Aviation Committee in 1984. In 1990 he set up R A Simpson, an aviation-fuelling consultancy and continues to serve on the Aviation Committee.

EI Certificates

Peter Rooney (left) of ConocoPhillips, Chair of the EI's Hydrocarbon Management Marine Transportation Panel PML 4, presents Bruce Nicholls of BP International with a Certificate of Appreciation for his work within the field of marine transportation hydrocarbon management. Bruce was a member of the PML 4 Panel for over 10 years and was Chair from 1999 to 2002.

Branch News

LONDON

Contact: *Ian K Robinson, T: +44 (0)1932 783774*

9 September: 18.00: *Launch of the Energy Institute,* by Louise Kingham, Chief Executive Designate, and *Airline Fuel Hedging,* by Phil Redman, Deloitte and Touche

NETHERLANDS

Contact: *e:* **IPNL@xs4all.nl**

25 September: 15.00–19.00: *Low Sulphur Fuels for Shipping*, Technical Meeting

ESSEX

Contact: *Arnold L Carlson, T: +44 (0)1268 794615*

8 October: 17.30: *Tank Cleaning and Processing of Sludge*, by Sarah Seenan, Willacy Oil Services

MIDLAND

Contact: *Margaret Ward, T: +44 (0)1299 896654*

15 October: 10.30: Visit to the Lubrizol Research Facility, The Knowle, Nether Lane, Hazelwood, Derbyshire

Discussion Groups

ENERGY, ECONOMICS, ENVIRONMENT

Talent Strategies – Managing the Attraction and Retention of Talented Individuals in Today's Market

Tuesday 14 October 17.00 for 17.30–19.00
Energy Institute, 61 New Cavendish Street,
London W1G 7AR, UK *Refreshments provided*

Speakers: **Iain Manson and Jon Glesinger, Energy and Natural Resources, Norman Broadbent**

Contact: **Laura Viscione**
T: +44 (0)20 7467 7174 F: +44 (0)20 7580 2230
e: lviscione@energyinst.org.uk www.energyinst.org.uk

NEW Publications

The IPPC Directive, Refinery BREF, and European Refineries – A Guidance Manual*

(Concawe, Boulevard du Souverain 165, B-1160 Brussels, Belgium. T: +32 2 566 91 60; F: +32 2 566 91 81; e: **info@concawe.be***). 32 pages. Free download from* **www.concawe.be**

This report has been prepared as a guidance manual for refining environmental and planning personnel who must prepare for the permitting and operational implications of the IPPC regulations that become applicable to existing operations in October 2007. New operations must already comply. The IPPC regulations have to be interpreted and enacted into national legislation, and detailed compliance will vary from country to country. A common resource for relevant technical information will be the series of reference documents for Best Available Techniques (BREF documents) prepared by the European Integrated Pollution Prevention and Control Bureau (EIPPCB) in Seville. This manual introduces the IPPC Directive and BREF document relevant to mineral oil and gas refineries, clarifying critical points and providing checklists of actions and debating points.

Thermodynamics – Applications in Chemical Engineering and the Petroleum Industry

*Jean Vidal (Editions Technip, 27 rue Ginoux, 75737 Paris Cedex 15, France. T: +33 (0)1 45 78 33 80, F: +33 (0)1 45 75 37 11, e:***info@editionstechnip.com***). ISBN 2 7108 0800 5. 512 pages. Price (hardback): 130; $130.*

The simulation of processes and their optimisation assumes that the thermodynamic properties and phase equilibria of the mixtures concerned are well known. This knowledge is still based upon experimentation, but it is also the result of calculation methods based on the basic principles of thermodynamics that govern them, ensure their coherence, and confer upon them a wide range of application. This text is primarily concerned with the description of these methods and their evolution. It is written for the student who wishes to apply the general principles (s)he has learned, and to the engineer confronted with a choice, occasionally a difficult one, of the most appropriate method to solve a problem. Computational examples are used to explain the application of the various concepts and models, while a comprehensive bibliography allows the reader to broaden the understanding (s)he has acquired.

The Resource Curse in a Post-Communist Regime: Russia in Comparative Perspective

*Younkyoo Kim (Ashgate Publishing, Gower House, Croft Road, Aldershot, Hampshire GU11 3HR, UK. T: +44 (0)1252 331551, F: +44 (0)1252 368595, e:***rkeane@ashgatepub.co.uk***). ISBN 0 7546 0963 4. 196 pages. Price (hardback): £47.50.*

As part of an attempt to resolve what makes economic reform in Russia difficult, this book examines how the energy sector has influenced economic growth and political development. It provides an in-depth analysis of the country's export of oil and gas, showing how the energy sector went through the 'topsy-turvy' period of Gorbachev's economic reform and the initial stages of market transition under Yeltsin. In doing so, it highlights the importance of the major oil and gas companies for the functioning of Russian politics.

* *Held in EI Library*

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New Editions to Library Stock

- *ASTM Standards on Disc: Section 5 Petroleum Products, Lubricants and Fossil Fuels: Volume 05.01 Petroleum Products and Lubricants (1): D 56- D 3230.* CD-Rom. American Society for Testing and Materials (ASTM), West Conshohocken, Pennsylvania, US, 2003.
- *BP Statistical Review of World Energy, June 2003.* BP, London, UK, 2003.
- *Energy and Power Risk Management.* Alexander Eydeland and Krzysztof Wolyniec. John Wiley & Sons, Chichester, UK, 2003. ISBN 0471104000.
- *Environmental Aspects of the Use and Disposal of Non Aqueous Drilling Fluids Associated with Offshore Oil and Gas Operations.* Report No. 342. International Association of Oil & Gas Producers (OGP), London, UK, 2003.
- *Forecourt Trader Business Directory 2003–2004.* 9th Ed. William Reed Directories, Crawley, UK, 2003. ISBN 1903115256.
- *Fuel and Fuel System Microbiology: Fundamentals, Diagnosis, and Contamination Control.* Frederick J Passman (Ed). ASTM Manual Series: Mnl 47. American Society for Testing and Materials (ASTM), West Conshohocken, Pennsylvania, US, 2003.
- *Managing Health for Field Operations in Oil and Gas Activities.* International Association of Oil & Gas Producers (OGP), London, UK, 2003.
- *Offshore Oil and Gas Directory 2003/2004.* 31st Ed. CMP Information, Tonbridge, UK, 2003. ISBN 0863825486.
- *Oil in the Sea III: Inputs, Fates, and Effects.* National Research Council/National Academies Press, Washington, US, 2003. ISBN 0309084385.
- *Petroleum Economist Guide to Offshore Projects.* Petroleum Economist, London, UK, 2003. ISBN 0306-395X.
- *Top 100: Ranking the World's Oil Companies 2003.* Petroleum Intelligence Weekly/Energy Intelligence Group, New York, US, 2003.

Contact Details

- **Information, careers and educational literature queries to:**
  Chris Baker, LIS Officer, +44 (0)20 7467 7114
  Sally Ball, LIS Officer, +44 (0)20 7467 7115
- **Library holdings and loans queries to:**
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  Sally Ball, IFEG Secretary, +44 (0)20 7467 7115

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IP Autumn Lunch

22 October 2003

Claridges Hotel
Brook Street, London UK

The IP Autumn Lunch is now an established date in the oil and gas calendar of events. It provides a unique opportunity to hear an internationally renowned figure speak on contemporary global issues relating to our industry.

The Institute of Petroleum is pleased to announce its sixth IP Autumn Lunch with Guest of Honour and Speaker

Dr Alvaro Silva-Calderón
Secretary-General, OPEC

Dr Silva-Calderón obtained a doctorate degree in law and politics from Universidad Central de Venezuela science in 1956. For over 25 years he has been a lecturer at the Law School of Universidad Central de Venezuela, Department of Mining and Hydrocar-bons Law. He is also an Emeritus Professor there and has taught in the postgraduate program on the Economy of Hydrocarbons.

Silva-Calderón started his career as a member of the advisory team of Juan Pablo Pérez Alfonso, and was President of the regional legislature of his home state of Monagas. Subsequently, he was a member of the National Congress, serving as President of the International Treaties Sub-committee and member of the Energy and Mines Committee.

He has been a columnist for national daily newspaper *El Globo* for several years, contributing articles on oil and the impact of oil activities in Venezuela. He is an active member of the Venezuelan Chapter at the World Petroleum Congress, where he has participated as Venezuelan delegate on several occasions.

He is a member of the National Energy Council and was appointed Minister of Energy and Mines of Venezuela in 2000, a position he held until mid-2002. In this capacity, he has actively promoted co-operation within OPEC and with non-OPEC oil producing countries. He was also actively involved in co-ordinating and organising the Second Summit of OPEC Heads of State, held in Caracas in September 2000.

On 1st July 2002, Dr. Silva-Calderón was appointed Secretary General of OPEC.

To apply for tickets, please complete this form in BLOCK CAPITALS and return it to the address below, together with payment in full. For further information please contact **Lynda Thwaite, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK.**
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Ticket price includes pre-luncheon drinks, and a three course lunch with wine. Cigars and liqueurs are not included.

Tickets will be allocated and mailed from the week commencing 1 September 2003.

In the event of cancellation of attendance by ticket purchaser a refund, less 20% administration charge of the total monies due, will be made provided that notice of cancellation is received in writing on or before 29 August 2003. No refunds will be paid, or invoices cancelled after this date.