Petroleum review

SEPTEMBER 1999

North Sea

- Project developments in 1999 and beyond
- Technology tackles challenging reserves

Decommissioning

Re-using offshore facilities

Lead replacement petrol

UK looks to a lead-free future

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

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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.

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ROUNDUP From the Editor

Indian summer for North Sea?

On reading his obituary in a newspaper, Mark Twain is said to have remarked that reports of his death were 'much exaggerated'. Much the same could be said of the North Sea. On page 33 we have tabulated the fields known to be coming onstream and the key prospects likely to become development projects. It is an impressive list. That said, it is also true that the projects are predominantly small with only limited reserves.

Earlier this year, following the disastrous fourth quarter when Brent actually went below \$9/b, it looked as though North Sea development might come to a shuddering halt. Now with Brent prices nudging \$20/b, North Sea developments are back on the agenda. Publicly, all the companies are extremely cautious and talking of \$10/b hurdles, but in private there is rather more optimism.

The basic, somewhat negative, background is that the North Sea is now well explored and understood. Large fields are unlikely, but more small accumulations will be found to add to those already discovered. Unlike the UK and the Netherlands, Norway has rather more large undeveloped accumulations. However, many of these feature high-cost gas which remains unattractive to develop at the moment.

The plight of Europe's platform fabrication yards is very real – many will be without work by the end of the year. This, however, reflects the industry's increasing move to floating and subsea production systems for all but shallow-water fields. This, is turn, has been at least partly driven by environmental legislation about platform removal at field abandonment. In short, new field developments won't save traditional fabrication yards – they will have to adapt to the new requirements if they are to survive.

For the oil companies the North Sea continues to offer a number of very positive advantages – although the companies rarely wish to say so publicly. The North Sea is an established hydrocarbon province producing from a range of structures and geological periods. There is an established production infrastructure and a comprehensive construction capacity close to hand. There is a ready pool of skilled manpower, sympathetic government and regulation, and a ready market for all that can be produced. Taxation is low (the UK is the second or third most attractive tax regime in the world, Norway less so).

So, what are the North Sea's disadvantages? Costs are high (although hungry contractors are effectively reducing this, as are the latest government and Crine initiatives), most of the large accumulations have been found, the weather is lousy, and it is not as sexy as drilling in the Caspian.

For the largest companies the North Sea is becoming a relatively unattractive place to spend their money. A Shell, Exxon or BP Amoco needs big projects to feed its hefty appetites. But, for as long as possible, such big players will want to keep their North Sea infrastructure loaded up. The current wave of ownership rationalisation is likely to facilitate this and produce a lot of small, effectively outstep, developments.

In the longer term, governments need to encourage the sort of small end-of-field-life specialist companies seen operating onshore and in the shallow offshore in the US. European governments concerned about the environment and the costs of final abandonment have always been chary about encouraging small companies – which can be characterised as asset strippers – to own and operate major oil facilities.

The US experience is very encouraging. It is possible to devise appropriate rules and safeguards. In a few years the major oil companies' North Sea assets will be minor, high-cost production. For small companies specialising in end-of-life assets, such assets would be their core business. They should be encouraged.

However, there is one 'white hope' for further major developments in the UK section of the North Sea. The UK and Denmark have now agreed a demarcation in the so-called 'white zone' between Shetland and the Faroes. Licensing of the area is due soon. A single major field would be enough to justify and pay for a pipeline to Shetland. Once this sort of infrastructure is in place, other known and likely finds could be developed. The whole story of the North Sea to date has been of finding and developing a large field and then using the infrastructure to develop a whole series of small fields. So far this strategy has been so successful that North Sea production has not yet peaked. It is probably now at, or close to, peak but largescale production and development will continue for many years to come.

Chris Skrebowski

Web World

North Sea sites

To tie in with *Petroleum Review*'s coverage of North Sea developments, this month's Webworld brings you a guide to related sites.

The Oil and Gas Industry Task Force website (**www.dti.gov.uk/ogitf/index.htm**) is designed to bring together government departments and the oil and gas industry to tackle key issues in both the short and long term. Published papers and Powerpoint presentations can be viewed online, or downloaded, and there are full details of all associated meetings and events.

North Sea Online – which can be viewed at **www.northseaonline.co.uk** – provides up-to-date information on over 250 fields in the North Sea that are due to come onstream between 1999 and 2003.

The Northern Offshore Federation (**www.nof.co.uk**) offers online resources, links, notice boards and articles.

Offshore Technology includes a list of North Sea projects, together with details of companies and equipment (**www.offshore-technology.com**). There is lots of other useful oil and gas information on the site, and what's more, registration is not required so there is no need to fiddle around with yet another username and password.

The Offshore Northern Seas Conference also has its own website – **www.ons.no** – with news, facts and figures, and of course full details of the ONS event itself.

You can find all these links and more on the Institute of Petroleum website at **www.petroleum.co.uk**

The new Members' Area of the IP website is to be launched on 15 September 1999. It will contain a collection of valuable resources, including:

- a searchable database of News in Brief stories
- the latest issue of *Petroleum Review*
- country information
- statistics
- reference material

If you haven't yet registered for a username and password, please e-mail Catherine Pope at the IP (**cpope@petroleum.co.uk**) with your full name and membership number.

If you have any questions or suggestions regarding the IP website or the Internet in general, please feel free to contact Catherine Pope – **cpope@petroleum.co.uk**

NEWS Upstream

First step in Maureen field decommissioning

Aker Offshore Partner has secured the contract for engineering related to the refloat and tow of Phillips Petroleum's Maureen Alpha platform in summer 2000. The award is the first step in the decommissioning of Maureen which is located in block 16/29a of the UK sector of the North Sea.

Since coming onstream in 1983, Maureen has produced more than 220mn barrels of oil. The steel gravity base platform was designed and built to be refloated and then re-used as a complete facility at another location. It is said to be the only large production, drilling and accommodation facility in the world designed with such a capability.

Phillips (33.778%) and co-ventures Agip UK (17.26%), BG (11.5%), Pentex (8.5%) and TotalFina (28.96%) are seeking to find a re-use opportunity for Maureen and are continuing to market the platform around the world in order to raise awareness of its potential and availability. The platform is suitable for use in water depths between 70 and 120 metres. Such areas would include the North Sea, offshore west and south Africa, southeast Asia, Australia, and South and North America.

If no total re-use opportunity is identified, other alternatives – including onshore deconstruction or using some of the platform components for civil engineering projects – will be considered.

Kuito development well on track

Chevron's FPSO destined for the Kuito field in block 14 offshore Angola was officially named *Kuito* last month in a ceremony in Singapore. After commissioning, the vessel will sail to the western coast of Africa where it will be spread moored in 1,260 ft of water above the Kuito field. The field is to be developed in phases, the first of which will see subsea wells connected to and producing into the *Kuito* FPSO. The field is expected onstream in 4Q1999 at an initial production rate of 50,000 b/d of oil. Output is forecast to rise to 100,000 b/d by the end of 1Q2000.

The *Kuito* FPSO has a production capacity of 100,000 b/d of oil and is capable of storing in excess of 1.4mn barrels. Crude oil will be exported via a buoy terminal designed to load VLCC size tankers. Chevron will time-charter the vessel from its owner, Sonsing, a joint venture of Sonangol and Single Buoy Moorings Production Contractors (SBM).

Eleven of the twelve planned production wells on Kuito have already been drilled and are currently being completed. A gas injection well is due to be finished this month. Production drilling is expected to complete early 2000, and will be immediately followed by the drilling of water injection wells. Associated gas is not to be flared, but will be used either as fuel for the FPSO or reinjected into the reservoir.

Kuito field partners are: Chevron (31%), Sonangol (20%), Agip (20%), TOTAL (20%) and Petrogal (9%).

Scottish Enterprise awards research fellowships

Scottish Enterprise Energy Group has awarded two oil and gas fellowships which aim to commercialise technologies currently under development at Heriot-Watt and Napier Universities in Edinburgh. The research projects are being undertaken by David Bowen, Senior Scientific Officer at the Department of Petroleum Engineering at Heriot-Watt, and John Harrison, Research Assistant at the Department of Biological Sciences, Napier University.

The Heriot-Watt project aims to develop a series of contacting and imaging sensor technologies bundled into a package of new analytical tools for use on rock cores. The Napier project is developing a novel way of removing oil contaminated waste drill cuttings generated in exploration and drilling through an advanced washing process.

In Brief

United Kingdom

Enterprise Oil reports that the 18/25-1 *appraisal well on the Corrib field offshore the west coast of Ireland has tested at 64mn cf/d of gas. The company says that output could rise to 100mn cf/d during full production. Field reserves are estimated at 1tn cf of gas.*

BP Amoco is reported to have *announced plans to invest between $650mn and $750mn in the North Sea every year over the next decade. The company has set a number of global upstream performance targets in order to meet this challenge. It plans to focus on finding and developing low-cost/high-volume resources, reduce E&P costs with a $2/b reduction targeted by the end of 2001, and ensure that operations are sustainable at a low oil price of $11/b.*

Following earlier measures introduced *to reduce red tape and address licence commitments, the UK Oil and Gas Industry Task Force (OGITF) has announced new proposals aimed at promoting supply chain benchmarking and collaboration towards competitiveness. It has also proposed an initiative in licence trading on the Internet (LIFT) aimed at reducing the time taken for transactions and cost of licence transfers, together with a number of measures to improve technology, skills and training.*

BP Amoco's Wytch Farm oil field in *Dorset is claimed to have achieved a new world record with its latest extended reach well which reached a total depth of 11,278 metres. The well, which is also said to have claimed the world record for horizontal length at 10,728 metres, took over 130 days to complete and is currently producing over 20,000 b/d of oil.*

Europe

Gulf Canada Resources' Q4-9 well on *the Q4 block in the Dutch sector of the North Sea has tested at 26mn cf/d and 28mn cf/d of gas from two zones. First production is expected at the end of 2000.*

Independent company Ramco Energy *has spudded its first well offshore Bulgaria. The Tangra-1 was drilled on the Shabla block 91-1. Results are expected in four to five weeks.*

Benchamas field enters production

Chevron's Benchamas field in block B8/32 in the Gulf of Thailand has come onstream. Initial production is 35mn cf/d of natural gas and 2,200 b/d of oil. This is expected to increase to 75mn cf/d and 25,000 b/d by October 1999. It is producing from three platforms, with 48 wells. Other satellite production wells are expected to come onstream in 2000. The gas is sold under contract to the Petroleum Authority of Thailand (PTT) and the oil exported via an adjacent FPSO facility.

Benchamas is the second of three known fields in block B8/32 to enter production. The Tantawan field began producing in February 1997 and Maliwan is expected onstream in late 2001. The block is estimated to hold proved and potential reserves of up to 3tn cf of gas and more than 350mn barrels of oil. Total production from the block is forecast to reach 145mn cf/d and more than 30,000 b/d by the end of 1999.

Chevron holds a 51.66% stake in the block and will become, subject to necessary government approvals, operator of the concession on 1 October 1999. Partners are: Thaipo (46.34%) and Palang Sophon (2%).

South Arne onstream

The South Arne field in blocks 5604/29 and 5604/30 in the Danish sector of the North Sea has flowed first oil. Five wells have been pre-drilled to date, the first of which is currently flowing at 7,000 b/d. Seven wells are to be drilled in total. The production facility is designed to process 50,000 b/d of oil and 70mn cf/d of gas.

The second largest field in production in Denmark, South Arne is expected, at plateau, to increase total Danish daily oil production by nearly 20%.

Field partners are: Amerada Hess (operator, 57.5%), Dong (34.3%), Denerco Oil (6.6%) and Danoil Exploration (1.6%).

First gas from Bell

The Bell field in the southern North Sea has produced first gas at an initial rate of 110mn cf/d.

The Bell well – drilled by Mobil as part of the Jupiter area development, with Conoco completing the subsea tie-ins and commissioning work – is tied back to the existing infrastructure in the Callisto South field. From Callisto, production flows to the Ganymede platform, through the Lincolnshire Offshore Gas Gathering System (LOGGS) and onwards for processing at the Conoco-operated gas plant at Theddlethorpe.

Field partners are: Conoco (operator, 20%), Mobil (50%) and Statoil (30%).

New pollution law for offshore UK waters

A new UK law, the Pollution Prevention and Control Act 1999, was given Royal Assent at the end of July, setting the framework for a new regime which will implement the requirements of the EU's Integrated Pollution Prevention and Control (IPPC) Directive.

According to UK Energy Minister John Battle, the Act 'provides the necessary powers' to 'integrate and improve environmental controls on companies exploring for and producing oil and gas in UK waters'.

Over the next year, proposed new regulations will provide extra safeguards over the use of chemicals offshore, building on the success of existing voluntary agreements. The government's power to control operations in the unlikely event of an offshore incident which threatens serious oil pollution is also to be strengthened.

The new IPPC Directive for new offshore facilities 'will ensure that best practice is applied to plant such as gas turbines, keeping emissions low and ensuring improved energy efficiency', commented Battle.

New Argentinian finds tie in to Lama Negra

Petrolera Argentina San Jorge – together with partners Repsol–YPF, Metro Holding and International Finance Corporation – has discovered two new oil fields in the Rio Negro Norte block in Rio Negro province in Argentina.

The first well tested at 2,415 b/d of gas, while the second tested at 4,227 b/d under natural flow conditions.

The new discoveries will be tied to the existing Lama Negra field complex production facilities which are currently producing 14,000 b/d of oil and are capable of handling up to 28,000 b/d without a major upgrade.

In Brief

Elf Petroland reports that a discovery *well on block L4a in the Dutch sector of the North Sea has tested at 895,000 cm/d of gas.*

Mol of Hungary has signed a contract *with Croatian state owned oil and gas company Ina to jointly explore for gas along the Hungarian–Croatian border.*

Saga Petroleum's North Sea Borg oil *field has come onstream. The field is currently producing 15,000 b/d. Phase one output is via the nearby Tordis subsea installation to the Gullfaks C platform for processing and offloading. Other solutions may be used for the second phase, which is expected to increase production to 30,000 b/d by 2001.*

North America

Shell Canada (60%) is understood to *have joined forces with Chevron Canada and Western Oil Sands to develop the $2.53bn Athabasca oil sands project in northern Alberta. Chevron and Western are expected to each fund 20% of development costs. The project, which is due onstream in 2002, is predicted to produce 170,000 b/d of synthetic crude oil.*

Canadian Natural Resources and Penn *West Petroleum are reported to have joined forces to buy BP Amoco's Canadian conventional and heavy crude oil assets for a total sum of $1.6bn.*

Phillips Petroleum is understood to be *selling its interests in 42 leases in 22 Gulf of Mexico fields to Newfield Exploration for $22mn.*

US independent Anadarko Petroleum is *reported to have doubled its acreage in the subsalt trend of the Gulf of Mexico following the acquisition of Texaco's average 50% working interests in 82 blocks for an undisclosed sum.*

Ocean Energy is understood to have sold *its stake in three Gulf of Mexico fields to Newfield Exploration for $66mn.*

Chevron Canada Resources and Poco *Petroleum have formed a natural gas exploration joint venture which is to target deep gas prospects in northwestern Alberta and northeastern British Colombia. Poco plans to finance 100% of proposed drilling during the next two years and expects to invest a total of $127mn in the new venture by the end of 2000.*

Strong oil price to boost North Sea investment

Rising oil prices and the continued strength of North Sea production boosted UK oil revenues by 34% in June, and combined oil and gas output reached its highest ever level on a 12-month moving average basis, according to the Royal Bank of Scotland's latest *Oil and Gas Index*.

Combined oil and gas production, while suffering its normal seasonal decline on May's figures, was 3.4% up on the year, and combined oil and gas revenues for June were more than 24% ahead of last year.

Oil prices reached an average of $15.91 for June, 31% higher than a year ago, and have continued to strengthen, breaching the $19 mark in July and early August.

Stephen Boyle, Head of Business Economics, said prices were remaining strong because there was continued evidence of firm adherence to production cuts by Opec and its allies. He commented: 'Higher prices are good news for the operators, bringing improved profits and stronger cashflow. However, the service and supply sector will have to wait until next year to see any benefits flow through to them. For investment to happen, operators need confidence that prices will remain above certain critical levels. If prices remain comfortably above $14 into the fourth quarter of this year – and are expected to stay there – investment next year should be higher than in 1999.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Jun	2,406,521	6,069	12.12
Jul	2,432,040	5,733	12.06
Aug	2,379,644	5,640	12.05
Sep	2,573,882	6,394	13.28
Oct	2,600,813	8,832	12.60
Nov	2,612,843	10,738	11.07
Dec	2,715,056	11,123	9.81
Jan 1999	2,664,121	11,532	11.16
Feb	2,678,138	11,532	10.20
Mar	2,679,786	11,107	12.54
Apr	2,717,767	9,863	15.66
May	2,507,093	7,349	15.18
Jun	2,397,667	6,785	15.91

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

First oil for Banzala

Chevron reports that its Banzala oil field, located in the block O concession offshore Angola, has come onstream on time and under budget. Production from the first three Banzala wells was expected to reach about 7,500 b/d by the end of July. In the initial development phase, five additional wells will be brought into production later this year, increasing output to 25,000 b/d. Banzala crude is sent via pipeline to Cabgoc's Malongo terminal.

Five further wells are to be drilled in phase two of the project, which could be onstream by 1Q2000.

The addition of production from Banzala's initial development phase is expected to bring total Chevron-led production in Angola's block O – currently averaging 480,000 b/d – to 500,000 b/d by the end of 1999. The company plans to boost oil production from its Angolan fields to 600,000 b/d by the year 2001.

Blake development

BG International is investigating development options for its Blake oil field discovery in block 13/24 in the outer Moray Firth, with a view to seeking sanction towards the end of the year.

One of the main options under consideration is a subsea development tied back to the Talisman-operated Ross field. A well recently drilled in block 13/29b has confirmed an extension to the Blake field.

Initial development plans will concentrate on the drainage of a reservoir estimated to contain recoverable reserves of between 50mn and 75mn barrels of light oil. 'There is also the potential to develop significant additional volumes outside the main reservoir', states BG.

Blake partners are: BG (44%), Amerada Hess (30.6%), Rigel Petroleum UK (17.6%), Talisman (5.4%) and Statoil UK (2.4%).

In Brief

Middle East

***Amec subsidiary King Wilkinson (Saudi** Arabia) has secured a three-year contract to provide design, engineering, construction and field engineering support for the Partitioned Neutral Zone (PNZ) Group's Kuwait oil fields. The PNZ Group is a joint venture between Saudi Arabian Texaco and the Kuwait Oil Company.*

***Daelim of South Korea is reported to** have secured a $290mn contract to construct the onshore gas processing facilities at the port of Assluyeh for the South Pars gas project in Iran. Work is due to complete in 2002. Samsung and local Iranian company Sadra have won the $200mn contract to build an offshore platform complex for phase one of the project.*

***Syria's Petroleum Company is reported** to have discovered a new oil field – Kamshi East – in the northeast of the country. Initial production capacity is put at 5,000 b/d of oil and just over 2mn cf/d of associated gas.*

Russia & Central Asia

***Shell is understood to have formed a** strategic alliance with TurkmenGaz and Turkmenneft to explore for and develop gas fields in Turkmenistan. Initial attention will focus on gas deposits that will supply the planned TransCaspian gas pipeline project.*

***Aminex is reported to have secured a** $17mn loan to develop the Kirtayel oil field in the Komi Republic in Russia.*

***Lasmo is understood to be planning to** sell its 12.5% interest in the Inam project in the shallow waters offshore southeast Azerbaijan – acquired following the company's takeover of Monument Oil & Gas earlier this year – in order to focus on exploration opportunities in Iran and Georgia. Inam's reserves are put at 1bn barrels of oil.*

Asia-Pacific

***A consortium comprising Boral Energy,** Woodside Energy and CalEnergy Gas (UK) is understood to have been awarded an oil exploration permit for area V98-2 in the Otway Basin offshore Victoria, Australia. Strike Oil secured a permit for area V98-4. Both areas are located near the undeveloped Minerva and La Bella gas fields.*

New era of understanding offshore UK

New consultation arrangements aimed at creating a closer relationship between the UK offshore oil and gas industry and trade unions were signed in August by representatives of oil companies operating in UK waters and union leaders.

The new arrangements establish a set of procedures to promote a more active dialogue within the industry on matters of 'common interest and concern'. Among these are procedures governing offshore visits by union officials and liaison with other industry representative bodies. The document also outlines how the UK Offshore Operators Association (UKOOA) and the Inter-Union Offshore Oil Committee (IUOCC) – which aim to meet at least four times a year – will work together to develop joint guidelines on good employment practices and the conciliatory role the two organisations could play in helping to resolve disputes or problems.

'There is a great deal of convergence in what the trade unions want to achieve by adding value to society and what the [oil and gas] industry needs to do to remain in business,' commented Bob Connon, UKOOA President. 'The new arrangements embody the new spirit of cooperation that has already been seen in the participation of the trade unions in industry initiatives such as the Step Change in Safety and the government's Oil and Gas Industry Task Force. But they take it one step further, opening doors for a closer relationship where the goal is a successful industry providing mutual benefits.'

Green light for Egypt's largest gas field

BG International and partner Edison International have signed a gas sales agreement with the Egyptian General Petroleum Corporation (EGPC) giving the go-ahead for what is claimed to be the largest gas field development in Egypt to date.

The Scarab/Saffron field, located in the West Delta Deep Marine concession in the Nile Delta, has estimated reserves in excess of 4tn cf of high quality gas. First production is due in January 2003. After a short build-up in output, the daily contract quantity is expected to be 530mn cf/d of gas over at least 17 years.

According to BG, this will be the first project in Egypt to use deepwater technology in depths of up to 700 metres.

The gas is to be sold to Egypt's rapidly expanding domestic market via the Nile Valley Gas Company (NVGC), a consortium of BG, Edison, Orascom and the Middle East Gas Association. NVGC is undertaking the development of the gas market and infrastructure in Upper Egypt under an exclusive 25-year franchise agreement with EGPC.

Myanmar Oil and Gas Enterprise has *discovered what is reported to be Myanmar's first oil gusher. Located in the Letpando oil field in Magwe, the gusher is reported to be producing 300 b/d of oil and 90,000 cm/d of gas.*

Premier Oil is understood to be plan*ning to sell half of its interest in the West Natuna gas project in Indonesia as part of a $200mn refinancing of its business. The stake is reported to represent around 500bn cf of gas.*

Santos' Pondrinie North 1 appraisal *well is reported to have flowed 2.7mn cf/d of gas, confirming the extension of the Pondrinie gas field in the Cooper/Eromanga Basins of South Australia.*

The Japan National Oil Corporation *(JNOC) is reported to be pulling out of two loss-making oil exploration projects in the Bonaparte Basin, offshore northwest Australia, and northern Ecuador.*

Santos is reported to have brought *onstream what is understood to be its first ever gas fields in Victoria, Australia. Gas from the Mylor and Fenton Creek fields in the onshore Otway Basin is to be processed at the company's new gas plant at Heytesbury, 160 km west of Melbourne. Up to 15 TJ (terajoules) of gas per day is to be sold under contract to state-owned company Gascor until 2003.*

China National Star Petroleum *Corporation (CNSPC) is reported to have found the first oil field in Tibet. The field, located in the Lunpola Basin in northern Tibet, is said to contain 3mn tonnes of proven oil reserves.*

The Petroleum Authority of Thailand *(PTT) is reported to have agreed a revised gas sales contract with the partners of Myanmar's Yadana project. The company is to take non-enriched gas from now until December 2006 in exchange for price reductions for the contract gas quantities it was supposed to have received from August 1998 to October 1999 but which it could not accept following delays in the construction of the Ratchaburi power plant.*

Nippon Oil Exploration is reported to *have doubled its stake to 20% in Ivanhoe Energy's planned Kongnan project on the Dagang oil field in China.*

In Brief

Latin America

Unocal and Petrobras are understood *to be planning to jointly develop the Pescada and Arabaiana oil fields in Rio Grande do Norte, Brazil. The US company is also reported to be planning to develop oil fields in Rio Grande do Norte, Sergipe, Alagoas and Bahia with the Ipiranga group.*

TOTAL (41%), Mobil (34%) and Tesoro *Bolivia Petroleum Company (25%) report that the ITAU X-1(A) discovery well on block XX West in the Tarija region of Gran Chaco province in southern Bolivia has tested at 795,000 cm/d of gas and 610 b/d of condensate.*

Arco is reported to be discussing the *sale of its Ecuador operations, including its 60% stake in the Villano oil field, and other Latin American assets to Burlington Resources.*

Petrobras (35%), Unocal (35%), YPF *(10%), Japex and Marubeni (combined interest of 20%) are planning to jointly explore the BC-9 offshore block in the Campos Basin offshore Brazil.*

Petrobras (35%), Mobil (35%, oper*ator) and Unocal (30%) have signed an agreement to jointly explore deepwater block BES-2 in the Espirito Santo Basin offshore Brazil.*

Shell Brasil has signed a partnership *agreement with Petrobras covering the deepwater BC-10 exploration block in the Campos Basin offshore Brazil. Shell is operator of the block, holding a 35% interest, Petrobras has a 35% stake, the remaining 30% shared equally between Esso and Mobil.*

Africa

Eni of Italy and the Libyan National Oil *Corporation are to jointly develop Libya's offshore block NC41 and onshore block NC169 which are estimated to hold 1.8bn boe of oil, gas and condensate reserves. The $5.5bn project is due onstream in 2003.*

NEWS Industry

Creating a single European market for energy

Agreement to accelerate the process of creating a single market in Europe for energy was made during a UK–Italy Summit in London last month.

Stephen Byers, UK Trade and Industry Secretary, and His Excellency, Pier Luigi Bersani, Italian Minister for Industry issued a joint statement saying that they agreed it was 'vital to drive forward the process of creating a single market for electricity and gas in Europe... and to ensure a level playing field in the European Union'.

They also said that Italy and the UK would jointly organise a conference in the 1H2000, involving industry and governments from all Member States, to discuss the implementation of a real single market in energy and outline solutions to problems which have arisen in the past.

In addition, Italian and British officials are to establish a joint working group to take forward joint initiatives in exchanging information on the state of the liberalisation process in the two countries. The working group will also look at means of accelerating the implementation of the European market for energy.

Mol embarks on restructuring programme

Hungarian oil and gas company Mol is reorganising its company structure. Most activities currently performed by its Upstream Division are to be restructured into two new units: Exploration and Production, and Gas Marketing and Power.

Activities carried out in the current Downstream Division will be performed by three new units: Supply, Refining and Logistics; Marketing; and Retail Marketing.

A new Chemicals Business Unit is also being established to manage the company's existing chemical product portfolio (including the sales of chemical feedstock and secondary products), manage chemical investments and develop future business opportunities in this sector.

US government turns down oil 'dumping' petition

The US Department of Commerce has turned down a petition submitted by an organisation of independent US petroleum producers, Save Domestic Oil Inc, alleging that Mexico, Saudi Arabia, Venezuela and Iraq had 'dumped' below-cost oil in the US market last year, reports *Peter Adam*. The Oklahoma-based group had sought oil tariffs of up to 177% against the four countries, each of which denied the allegations.

Many industry organisations in the US, including the API, also contested the charges. Critics of the petition included Mack McLarty, former White House Chief of Staff and CEO of Entergy, a natural gas utility, and Daniel Yergin, Chairman of Cambridge Energy Research Associates, who together had warned that imposing the tariffs would 'damage our relations with key allies, increase energy costs for US consumers and provide little real help to those who filed the complaint'.

Their points were consistent with the findings of a study issued by the Petroleum Industry Research Association (PIRINC) in early August. Last year's oil price decline, PIRINC showed, was due to multiple, unexpected, 'exogenous' shocks, that, taken together, represented virtually a 'once-in-never' oil market occurrence. These included financial difficulties and recessions in Asia and Russia, unseasonably warm weather, Opec's 1997 decision to raise production by 700,000 b/d and the UN-authorised increase in Iraqi exports.

PIRINC also took note of the dire circumstances that drove independent producers to take such action, stating: 'Independent oil companies are generally not financially strong enough to weather long periods of low prices.'

According to US Bureau of Labor Statistics figures, the E&P sector of the US petroleum industry has lost over 67,000 jobs since November 1997 – the independents accounting for over 40,000 of these. Over the same interval, the aggregate market capitalisation of publicly held independents declined by, at one point, $20bn, as valuation losses certain oilfield service companies suffered approached 80%.

While the petition's critics pointed out that a vibrant domestic oil industry is essential to US interests, all they have to offer are temporary reductions or elimination of State and Federal royalty and severance taxes during temporary periods of low prices.

As the US becomes increasingly dependent on foreign supplies of crude oil, international policy concerns and geopolitical considerations eclipse the interests of domestic independent producers.

In Brief

United Kingdom

BP Amoco has posted a 13.6% *increase in 2Q1999 replacement cost net income to $1.23bn.*

Shell reports that its 2Q1999 results *were up 5%, at $1.614mn on an adjusted current cost of supplies basis, and up 30% on a reported net income basis compared with the same period a year earlier. The company also reports $450mn of cost improvements in 1H1999 towards the target of $2.5bn by 2001.*

Lasmo has posted a £28mn net profit *for 1H1999, up from a loss of £4mn for the same period in 1998.*

Helen Liddell has replaced John Battle *as UK Energy Minister. She will also have responsibility for European Affairs, taking over from Lord Simon who has resigned from government. Battle will be moving to the Foreign Office.*

BG plc has unveiled plans to invest *$5bn on doubling the size of its international division over the next four years. The expansion plans include an increase in return on capital to 20% by 2003 and boosting oil and gas production from 235,000 b/d to 425,000 b/d. Much of the investment will focus on projects in Kazakhstan, Argentina, Egypt, Trinidad and Brazil, where BG already has operations in place.*

Europe

Statoil's Board of Directors is reported to *have called for the Norwegian state oil company to be partially privatised and listed on the Norwegian stock exchange. It has also recommended that the State Direct Financial Interest (SDFI), which controls a large proportion of Norway's known oil and gas reserves and is managed by Statoil, be merged wholly or partly with the state company.*

Norway's government has unveiled a *new initiative which will help fund and promote new Norwegian projects worldwide. The NKr100mn Demo 2000 project will focus on reservoir description and interpretation, deepwater technology, subsea processing, multiphase transport, drilling and well engineering. It is hoped that the project will help forge more direct links between researchers and suppliers, and between specific field developments and those under consideration.*

NEWS Industry

UK fast-tracks air quality targets

Following the Government's recent review of the UK National Air Quality Strategy, it is proposed to tighten objectives for five of the eight pollutants covered by the strategy.

The target date for achieving reductions in emissions of benzene (to 5 ppb measured as a running annual mean), 1,3-butadiene (1 ppb; running annual mean) and carbon monoxide (10 ppm; running 8-hour mean) is to be brought forward from 2005 to 2003, with a new tougher indicative level to be set for benzene (1 ppb by 2005). For lead, the date for achieving the objective is to be brought forward from 2005 to 2004, with a new tougher objective to be set (0.25 $\mu g/m^3$) for 2008.

The annual objective for nitrogen dioxide (21 ppb; annual mean) is not to be changed, but the hourly objective is to be tightened to 104.6 ppb (previously 150 ppb) and a new objective for the protection of vegetation is to be introduced for 2000.

The objectives for ozone (50 ppb; 97th percentile of running 8-hour mean) and sulfur dioxide (100 ppb; 99th percentile of 15-minute mean) remain unchanged, although, for sulfur dioxide, a new objective for ecosystems is to be introduced for 2000.

For particulate matter (PM10) the present objective (50 μ/m^3; 99th percentile of 24-hour mean) is to be retained as an indicative level. The more relaxed limit values in the Air Quality Daughter Directive are to be introduced as objectives for 2004. The original objective was set on the basis of limited knowledge at that time and the consultation indicates that this will not be achievable by national measures alone. Transboundary pollution from Europe accounts for a significant proportion of annual mean concentrations of PM10. As a result, concerted action is needed at the European level to reduce particulate emissions, an issue the UK government plans to pursue with other Member States.

EC questions golden shares in Elf Aquitaine

Golden shares retained by the French government when it privatised Elf Aquitaine, which allowed it to exercise guaranteed power over the company's operation, are to be the subject of a court case at the European Court of Justice, reports *Keith Nuthall*. The European Commission is seeking an order declaring that the shares break European Union laws on the free movement of capital and the right of establishment.

Under the French 1993 Privatisation Act, Decree 93–1298 of December 1993 converted ordinary shares held by the French government into 'specific shares' to which special powers were attached. These powers include:

- prior approval by the Minister of Economic Affairs for any acquisitions of shares which would take holdings above the thresholds of one-tenth, one-fifth or one-third of the capital or of the voting rights;
- the right to appoint two representatives to sit on the company's board;
- the right to veto any decisions putting up as guarantee the majority of the capital of four subsidiaries of the parent company.

In a report, the Commission has insisted that under European law, all restrictions on the free movement of capital and on the right of establishment 'must apply in a non-discriminatory manner'. It said that they must also 'be justified by imperative requirements in the general interest, must be suitable for securing the attainment of the objective pursued and must not go beyond what is needed to attain it'.

In this case, says Brussels, 'the use made by the French State of these special powers... creates uncertainty for investors as regards the terms on which shares in the company can be acquired'. It adds: 'EU law requires that the authorisation procedure be justified by imperative requirements in the general interest and be based on a set of objective criteria, be stable over time and be made public. The present arrangements for the exercise of the special powers available under the French legislation do not satisfy these requirements.'

In Brief

North America

***It is reported that Global Industries of** the US is to acquire ETPM of France for $265mn. The merger will create what is claimed to be the world's largest offshore construction company in market capitalisation terms with combined 1998 revenues of $1.3bn.*

***TotalFina has launched the US phase of** its takeover bid for Elf Aquitaine, offering to exchange four of its shares for three Elf shares and four of its American Depositary Shares for every three Elf ADSs.*

***US independent Unocal has reported a** 70% fall in 2Q1999 earnings to $19mn compared with the same period a year earlier. Texaco posted a 2Q1999 income of $286mn, 15% less than the $335mn recorded during the same period in 1998, while Arco reported 2Q1999 net income of $313mn, compared with $154mn in 2Q1998. Chevron announced a 2Q1999 net income of $350mn, a decrease of 39% from net income of $577mn for the 1998 second quarter. Mobil posted 2Q1999 earnings of $650mn, only slightly lower than the $655mn figure recorded for the same period a year earlier.*

Middle East

***BP Amoco is understood to be planning** to sell its 9.5% interest in the Offshore Kazakstan International Operating Company (OKIOC) oil consortium which is currently exploring for oil on the Caspian Sea shelf.*

Latin America

***Petrotrin, the state-owned petroleum** company of Trinidad and Tobago, is reported to have formed a joint venture with Suriname state-owned company, Staatsolie, to undertake upstream and downstream projects in Suriname.*

Africa

***The Nigerian government is understood** to be planning to divest 40% of its equity holding in 10 companies quoted on the Nigerian Stock Exchange by the end of the year. The companies include Unipetrol, National Oil and Chemical Company, and African Petroleum.*

Statoil service stations in Scandinavian alliance

A new player is to be established in the Scandinavian fuels retailing market following approval by the European Commission for a new joint venture between wholesale and retail daily consumer goods and services group ICA of Sweden and Norwegian oil company Statoil, reports *Keith Nuthall.*

Under the deal, ICA's Norwegian subsidiary, ICA AS, will acquire 50% of the shares in Statoil Detaljhandel Skandinavia AS. The new venture plans to establish a network of service station shops throughout Scandinavia. Statoil is to transfer its existing service station operations in Sweden, Norway and Denmark to the joint venture, which is likely to sell a broad range of consumer goods as well as fuel.

The deal will not affect Statoil's exploration, production, transportation and refining of petroleum and its derivatives. Nor will it affect the company's string of service stations in Ireland, Poland, the Baltic States and Russia.

The European Commission in Brussels decided that the new group formed by the alliance would not be so dominant in the marketplace that it would harm competition. Its report stated: 'The operation will have effects on several different product markets. However, in each market the increase in market share is limited and there are other major competitors present to ensure effective competition, and other filling station networks which may develop their shops supplying daily consumer goods. The Commission has therefore concluded that the operation does not give rise to competition concerns in the European Economic Area [the EU, plus Norway, Iceland and Liechtenstein], and has consequently decided not to oppose the operation.'

Egyptian gas project comes onstream

The Salam gas plant – part of the Western Desert gas project in the Khalda concession in Egypt – has come onstream. Project partners Repsol–YPF (operator, 50%), Apache (40%) and Novus (10%) have invested $300mn to develop gas reserves in the Khalda concession which have been discovered over the past six years.

The project consists of the Salam and Tarek gas processing plants and a trans-Western Desert gas trunk pipeline linking Khalda to the National Pipeline Grid system of Egypt at Armeriya, west of Alexandria. The Salam plant is designed to handle 200mn cf/d of gas while the Tarek facility, due onstream soon, will be capable of handling 100mn cf/d.

Around 200mn cf/d of Khalda gas is to be sold to the Egyptian General Petroleum Corporation (EGPC) under a take-or-pay contract. A further 50mn cf/d will be transported through a southern gas pipeline, currently under construction, to Dahshur, south of Cairo. Together, these two volumes of gas represent 18% of the current total gas production of Egypt.

Once completed, the Western Desert gas project will boost production from the Khalda concession from 37,00 boe/d to more than 100,000 boe/d.

UK clean vehicle task force tackles air pollution

The UK Cleaner Vehicles Task Force – comprising representatives from the UK government, industry and special interest groups – has recommended a number of actions to tackle air pollution and climate change in its first published report. These include:

- Informing consumers through better information on fuel consumption, emissions and noise; a clear vehicle label showing environmental information; the promotion of improved maintenance and better driving styles; encouraging regular emission testing at minimal cost in standard vehicle servicing; increased testing facilities, and developing self-testing for emissions; and effective onboard driver information systems to give data on emissions.
- Improving enforcement by developing roadside emission testing to target the worst polluters effectively; improving the MOT emissions test; and developing low emission zones to improve air quality in urban areas.
- Promoting technological solutions by encouraging retrofitting for existing vehicles; promoting alternative fuels and the infrastructure to supply them; and supporting R&D into alternative fuel sources, new engines and other vehicle and fuel technologies.
- Supporting fleet operators by developing greener fleet certification schemes; encouraging the adoption of voluntary targets and providing best practice guidance.

In Brief

United Kingdom

Shell has launched a new 10w-40 semi- *synthetic heavy-duty diesel engine oil, Shell Rimula Super FE, which is said to improve fuel economy and facilitate longer drain intervals. It has also extended its range of Shell Rimula truck and bus lubricants with the introduction of an upgraded specification for its Rimula Super mineral oil.*

International Petroleum Exchange *(IPE) Chief Executive Lynton Jones is understood to have resigned after a vote for demutualisation of the exchange fell short of the requisite number required to proceed. Executive Vice President of Business Development Richard Ward has been named as temporary Chief Executive.*

Shell UK is launching a new range of *high performance lubricants in easy-to-use aerosol cans. The ten lubricant products are packaged in 500 ml cans for use in a number of applications ranging from general purpose maintenance and cleaning to specialised lubrication in the industrial, automotive, marine and service sectors.*

Mobil Gas Marketing has secured a *13% share of the UK industrial and commercial gas market according to analyst Datamonitor. According to a recent report, although Business Gas remains the dominant player (20.9%), continued erosion of its share since competition began over a decade ago means that the major independents are now in a position to challenge its leadership, particularly in the interruptible and large firm sectors. Mobil Gas is the leading independent, followed by ENG (11.7%), BP Gas (11.4%) and Shell Gas Direct (9.3%).*

UK motor traffic levels in 1998 showed *a 1.5% increase on 1997 figures, lower than the 2.3% increase in the previous year, according to the latest road traffic statistics published by the UK Department of the Environment, Transport and the Regions (DETR). Motorway traffic rose by 4% between 1997 and 1998, while traffic on major built-up roads fell by 1% over the same period. The 1998 level of goods vehicle traffic was 15% higher than ten years earlier.*

Independent oil company Maxol is to *implement a new loyalty scheme, Points Plus, at 260 of its outlets in Ireland at a cost of IR£750,000.*

Petroleum barges return to UK inland waterways

UK Transport Minister Glenda Jackson officially opened in July Bayford Thrust's refurbished oil storage depot on the British Waterways managed Aire & Calder Navigation near Leeds, welcoming the return of petroleum-carrying barges to the northeast inland navigation for the first time in many years. Over the next five years, 200,000 tonnes of petroleum products are to be moved from Humber refineries to the storage depot by barge, contributing to the overall reduction in tanker journeys made on the region's roads.

The upturn in freight carrying on the nation's waterways, after a long period of decline, follows the government's recognition that up to 3.5% of all road freight has the potential to be transferred onto inland waterways and coastal shipping routes. Studies indicate that transporting petroleum in barges each carrying 500 tonnes could save 16,500 lorry journeys over five years.

Provisional UK energy statistics released

The UK Department of Trade and Industry (DTI) recently published provisional statistics showing energy production and consumption and petroleum product prices in the 2Q1999. Some figures for typical retail prices of petrol and diesel fuel in July are also given.

Production of indigenous primary fuels in the 2Q1999, at 69.3mn toe, was 2.9% higher than in the corresponding period a year earlier. Production of coal fell by 7.1% while production of oil, gas and primary electricity rose by 1.1%, 8.6% and 5.9% respectively.

Total inland consumption of primary fuels – which includes deliveries into consumption – at 51.6mn toe, was 2.7% lower than that recorded for the 2Q1998. Consumption of gas and primary electricity rose by 0.9% and 5.1% respectively, while coal and oil consumption dropped by 15.9% and 1.7% respectively. Consumption of coal fell due to lower levels of its use at power stations, states the DTI.

Total use of petroleum, including non-energy use, in the period was 19.2mn tonnes, 2.5% lower than a year earlier. Energy use decreased by 1.7% while non-energy use increased by 3.7%. Total petrol deliveries were slightly lower (down 0.4%), with deliveries of unleaded petrol 9.4% higher. In the period, unleaded petrol deliveries represented 85.6% of total motor spirit deliveries, compared with 77.9% a year earlier. Diesel fuel deliveries were virtually the same (up 0.2%) while deliveries of other gas diesel oils, primarily for heating purposes, decreased by 2%. Fuel oil deliveries fell by 22.7%, continuing its decline as a source of energy for industry and electricity generation. Deliveries of other products decreased by 1.8%, with increased deliveries of aviation fuel being offset by decreased deliveries of burning oil and liquid petroleum gases.

Prices of motor fuels fell slightly in May and June but picked up sharply in the month to mid-July by around 1 p/l each for 4-star, premium unleaded and diesel. It should be noted that from July 1999, diesel prices are for ultra-low sulfur diesel (ULSD) which now accounts for over 90% of all diesel sales. As such, the data are not strictly comparable with earlier figures. However, differences in final selling prices between 'regular' diesel and ULSD are negligible, states the DTI. In the year to mid-July 1999, rises of 5 p/l, 5.9 p/l and 6.9 p/l were seen for premium unleaded, 4-star and diesel respectively, the largest rise since June 1998 and representing increases of around 7.5% to 10% in the price of these fuels. In the month to mid-June, the price of superunleaded fell by 0.1 p/l but was around 6.5% higher than a year ago – an actual increase of 4.9 p/l.

Progress for TransCaspian gas pipline project

PGS International and Shell are to join forces on the TransCaspian gas pipeline project. Together, the new partnership plans to spearhead the development of the project that will initially transport 16bn cm/y of gas from Turkmenistan to Turkey, via the Caspian Sea, Azerbaijan and Georgia. Shell joins PGS as a sponsor of the project, taking a 50% interest.

The government of Turkmenistan has signed an agreement with PGS establishing the commercial and legal framework for the project. Key elements of the agreement include the preliminary financing for the project, tariff structures, gas field designation, the provisional pipeline corridor and the government's participation in the project.

PGS and Shell plan to conclude negotiations later in the year on a series of legal and commercial agreements with the governments of Turkey, Azerbaijan and Georgia. The two companies are also to select additional consortium partners.

In Brief

Europe

***Wingas of Kassel, Germany, has** secured a contract to deliver 200mn cm/y of natural gas to Munich-based Wacker Chemie's new combined cycle power station from 2001.*

North America

***Syntroleum and speciality chemical** company Lubrizol have unveiled plans to develop and test additives for use in clean fuels manufactured using Syntroleum's proprietary gas-to-liquids (GTL) process. Initial work will focus on developing additives to enhance the performance of 'designer fuels' being developed under Syntroleum's previously announced programme with DaimlerChrysler.*

***Classification society ABS has received** formal authorisation from the US Coast Guard to act on the US government's behalf in issuing International Certificates of Fitness for chemical carriers and liquefied gas carriers. ABS says that it is the only classification society to have received such authorisation to date.*

***Murphy Oil Corporation is understood** to be selling 60 of its Spur-branded service stations in the southeastern region of the US to private companies for a total of $31.5mn. The funds are to be used initially to reduce debt and ultimately redeployed to fund the company's venture with Wal-Mart Stores which aims to have 130 forecourts in operation by the end of 1999.*

Russia & Central Asia

***The Russian government is reported to** be planning a major reorganisation of the country's fuels retailing sector which will put all service stations under the control of major oil companies.*

***Lukoil is reported to be buying a 58%** stake in Bulgaria's largest oil refinery, Neftechim, for $107mn. The Russian oil company is also understood to be planning to invest heavily in a modernisation programme at the facility.*

***Fortum's Russian subsidiary, Neste St** Petersburg, has started operations at its new 500,000 t/y capacity import terminal for petroleum products in St Petersburg. The company also operates 18 Neste service stations and three diesel fuel outlets in St Petersburg and Vyborg.*

Pilot gas-to-liquids plant onstream

Arco and Syntroleum Corporation's 70 b/d gas-to-liquids pilot plant at Arco's Cherry Point refinery near Bellingham, Washington, US, came onstream at the end of July. The pilot plant is testing new reactor designs and a high-performance Fischer-Tropsch catalyst for the Syntroleum Process, a proprietary process for converting natural gas into synthetic fuels and hydrocarbon-based speciality chemicals.

The pilot plant incorporates proprietary reactor designs for the autothermal reformer and the Fischer-Tropsch synthesis reactor system. The autothermal reformer uses natural gas and air to produce synthesis gas, a mixture of hydrogen and carbon monoxide. The synthesis gas is processed in the Fischer-Tropsch reactor to produce a raw synthetic hydrocarbon product, which is then processed in separate steps into fuels that are clean, contain no sulfur or aromatics, and can be distributed through the existing fuel distribution infrastructure and burned in conventional engines.

'The successful integration of the new [Fischer-Tropsch] catalyst system and the advanced reactor design represents a major step forward in assessing this important technology,' said Jeff Bigger, Arco's Gas-to-Liquids Technology Manager. 'We will build upon the knowledge gained in this plant to refine our design concepts for large-scale plants. Our ultimate goal is to deploy an economically attractive design for commercialising stranded natural gas resources.'

Seeking agreement on WAGP project

The West African Gas Pipeline (WAGP) project recently got the green light from the governments of Benin, Togo, Ghana and Nigeria to proceed with development planning. However, plans to finalise the agreement by outlining the structure of the joint venture running the project and installing Chevron as project leader were being hampered as *Petroleum Review* went to press, following the Nigerian National Petroleum Company's announcement that it should lead the project.

The WAGP project is being developed by a consortium of six companies – Chevron, Ghana National Petroleum Company, Nigerian National Petroleum Corporation, Shell, Societe Beninoise de Gaz and Societe Togolaise de Gaz.

The $400mn, 990 km pipeline – which is due to be commissioned in 2002 – will initially carry 120mn cf/d of Nigerian gas to power generation customers in Ghana, Togo and Benin. Volumes may double or triple over the life of the project as markets grow and existing industries convert to gas, comments Chevron.

In addition to bringing much needed energy to this part of Africa, it is envisaged that the project will make a significant contribution to the economies of the participating nations. Studies indicate that WAGP will create thousands of direct and indirect jobs in the four countries by providing low-cost fuel for industrial and commercial development. The project is also expected to significantly impact the environment via its planned 100mn tonne reduction in greenhouse gases. George Kirkland, Chairman and MD of Chevron Nigeria, explains: 'Diminished flaring of natural gas will reduce the amount of greenhouse gas emissions, while the availability of natural gas for power generation, which will reduce the need to use less-environmentally friendly fuels, will further decrease air pollutants.'

Asia-Pacific

Enron is understood to be planning to *invest $1bn on LNG infrastructure facilities in India over a three-year period. The US company is hoping to sell 2.6mn t/y of imported LNG to power companies and steel and fertiliser producers.*

It is understood that Western Australia *is to become the first state in Australia to ban the use of leaded petrol, effective from January 2000. It is reported that fuel producers will not only be required to remove lead from the fuel (to be replaced with an alternative additive) but also to reduce levels of benzene and MTBE, two known carcinogenics.*

Petronet of India has signed a 25-year *contract with Qatar's Rasgas for the purchase of 7.5mn t/y of LNG.*

Japanese oil distributor Nippon *Mitsubishi Oil is understood to have launched a $224mn friendly takeover bid for refining company Koa Oil which is 50% owned by Caltex of the US. Nippon Mitsubishi Oil already holds a 5.8% interest in Koa Oil.*

Chevron is understood to have agreed *to purchase from Queensland's Allgas utility 130 PJ/y of gas for a 20-year period. It is reported that the new sales agreement will help increase the viability of the proposed $3.6bn Papua New Guinea–Queensland gas pipeline.*

Latin America

Dominion Resources is reported to *have sold its Latin American power generation assets to Duke Energy Corporation for $405mn.*

UK Deliveries into Consumption (tonnes)

Products	†June 1998	*June 1999	†Jan–June 1998	*Jan–June 1999	% Change
Naphtha/LDF	247,417	234,866	1,476,543	1,592,619	8
ATF – Kerosene	801,505	750,465	4,200,108	4,369,787	4
Petrol	1,842,748	1,794,648	10,688,182	10,536,872	–1
of which unleaded	1,436,130	1,545,148	8,221,529	8,893,711	8
of which Super unleaded	32,394	29,607	206,370	172,328	–16
Premium unleaded	1,403,736	1,515,541	8,015,159	8,721,383	9
Burning Oil	213,399	180,151	1,826,937	1,947,603	7
Automotive Diesel	1,298,689	1,266,008	7,429,230	6,420,767	–14
Gas/Diesel Oil	541,410	507,424	3,577,128	3,442,542	–4
Fuel Oil	193,974	159,158	1,462,297	1,140,773	–22
Lubricating Oil	70,532	75,643	421,546	399,553	–5
Other Products	629,003	682,430	4,048,129	5,296,662	31
Total above	5,838,677	5,650,793	35,130,100	35,147,178	0
Refinery Consumption	554,972	486,593	3,238,013	3,153,431	–3
Total all products	6,393,649	6,137,386	38,368,113	38,300,609	0

† Revised with adjustments *preliminary

New drilling techniques extend life of mature fields

The UK sector of the North Sea is now strewn with ageing platforms and their associated drilling rigs. Some of these rigs were installed as second-hand units and most have some form of second-hand equipment. Drilling demands are increasing as these rigs are ageing, with economic targets becoming harder to access as they are located either in tight infill locations within the main field or at the far reaches of the main field and in accumulations beyond. *Jack Winton* of KCA Drilling* looks at the drilling technology that is being developed to exploit such reserves and extend life of field.

The further into a field development project, the greater the requirement for sophisticated well design in order to access once impossible or uneconomic infill targets around faults and other wells which, in turn, achieves greater reservoir exposure and improves productivity. Extended reach wells are being drilled from platforms to exploit near facilities potential (NFP) locations, with the drilling rigs and downhole equipment taken to their maximum capability and, in some unforeseen cases, beyond.

To fulfil these demands, the well engineer is turning to more and more innovative drilling techniques and new technology. The mature field is now the scene of young technology and new ideas to provide sustained production profiles and an extended life of field.

The drilling sequence

The platform well engineers live by, and for, their drilling sequence. Recent oil prices have reminded us of the fact that the value derived from a well's cost and its subsequent productivity, however it is measured, has a major impact on the future drilling sequence.

But another factor has produced turmoil in the drilling sequence. New seismic data and/or the reinterpreting of old data with greatly increased processing power has led to reassessments of field development plans. This, of course, has meant some casualties and much shortened drilling programmes but in the main has increased the number of economic targets and brought a refreshing impetus to the development of mature fields. Improved resolution and interpretation techniques have led to the reassessment of once marginal locations, and targets are generated with far greater confidence.

This new impetus demands ever more innovation in terms of equipment and procedures to ensure wells with a complex architecture are delivered cost effectively.

New technology and techniques

In the long term, the implementation of new technologies is clearly the answer. However, oil companies are screening their wells at low oil prices, making every well marginal, and therefore the well engineer increases unwanted risk every time a piece of new technology is used in a well. As the greatest budget savings come from operations that run smoothly, the potential risk of disruption through new technology makes drilling teams uncomfortable about its introduction.

It can be shown that where a problem occurs well times can increase significantly. **Figure 1** shows a survey of 45 wells demonstrating two discrete trends while drilling 8-inch hole sections. Where the section was drilled to plan, with no problems, the trend shows time was increasing gradually with the length of each section. Where wells have experienced problems, the section times are doubled in comparison to trouble-free wells at equivalent depths.

The real cost savers seen recently are not those applying new technology but those applying new techniques. Recent exceptional performances in the North Sea have been the result of proven technology or new techniques which use older technology more efficiently. Straightforward well trajectories, data acquisition programmes and completions programmes have meant experience can be drawn on and improved upon. Several of these wells have been drilled at half the budgeted cost.

'Proven technology' can, of course, be interpreted differently. New tools and techniques tested prior to the lower oil prices used the luxury of wells that were not so economically marginal. Financially, there was room for failure. These tools

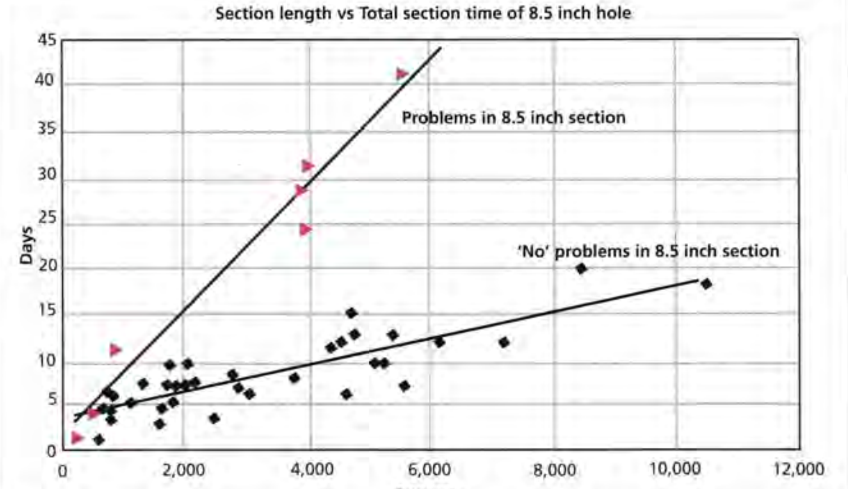

Figure 1: No problems means the section is drilled in less than half the time

and techniques, which have some testing history rather than a proven history, now find favour in an environment of tighter budget control. To expect the rig teams to run brand new technology under the overhanging accountability cloud of the current climate is perhaps naïve. To expect them to run 'proven technology' using every technique possible to reduce times and perform operations off the critical path is far more realistic.

CTD, TTRD and MLs

A total of 22 coiled tubing drilling (CTD) operations have been attempted since 1993 in the UK North Sea (although many more onshore UK). These include simple hole deepenings to through-tubing kick offs with horizontal sections. It is somewhat of a surprise that only one through tubing rotary drilling (TTRD) well, that uses smaller drillpipe through the completion, has been drilled.

In hindsight, the logical step from full-blown side tracking, where completion recovery is required, is TTRD rather than CTD. The same size restrictions apply to the downhole tools yet the operation can be performed from a rig with traditional drilling techniques.

TTRD may yet see a resurgence, especially as CTD drilling has yet to prove its cost effectiveness in the UK North Sea. Further progress may be seen as new high torque drill pipe connections are now available, standalone hydraulic workover units become available and the de-mothballing and utilisation of stacked platform rigs is addressed.

A third approach is also being used to target infill locations: multilaterals (MLs). This drilling technique has seen a more conventional evolution. The first wells that were drilled utilised new applications of proven tools and procedures to construct the main bore/lateral junctions. More advanced MLs are now using new, purpose built and designed equipment.

All three technologies are of course ideally suited to target marginal infill locations, accelerate production and improve a field's ultimate recovery.

ERD and old platforms

Drilling wells to new infill locations does not generally pose problems to the platform's older drilling rigs but technical difficulties can arise when drilling to extended reach NFP locations. Recent advances in extended reach drilling (ERD) equipment and techniques allow additional reserves to be developed (see **Figure 2**). The techniques include advances in computer modelling for wellpath design and improved operating practices from experience gained on extended reach drilling.

Challenges on the surface for drilling ERD wells are equipment limitations and logistics or supply problems. Most of the standard drilling parameters such as surface torque and mud pump pressure will be operating close to the maximum capacity for platform drilling equipment. To ensure not only that the well can be drilled but also to reduce the risk of problems, some rig upgrades or temporary installation of equipment may be necessary.

Although some wells of around 25,000 ft measured depth have been achieved using kellys, a high specification top drive would be considered essential to provide the torque for confidently drilling longer reach wells. These are relatively inexpensive to install, especially where the cost can be spread over several wells. Powerful, portable top drives can now be rented and installed on a well by well basis. While additional mud pumps, shakers and an up-rated circulating systems are certainly beneficial, most ERD wells are drilled with standard equipment. This can often be supplemented, for example by installing a temporary additional mud pump.

Logistics and supplies must be carefully managed on ERD wells since the storage requirements for casing or bulk materials often exceeds rig capacity. Such problems can be compounded by poor weather conditions. For example, a deep $9^5/_8$-inch casing string could require in excess of 600 joints of casing, which would generally exceed the capacity of the pipe deck. Limited mud storage capacity can be upgraded by installing temporary storage tanks. A supply vessel can be held alongside for critical stages of the well, such as changing mud systems or for taking returns from the well when displacing casing cement jobs.

Challenges are not only confined to the surface but are also found downhole. Formation and borehole problems, including issues such as wellbore stability, mud hydraulics, and torque and drag, must be carefully managed.

Wellbore stability covers both mechanical and chemical stability and predictive models based on field studies are used to determine the mud weight and chemistry required for stability at the hole angle required.

Optimised drilling fluid hydraulics for ERD wells are critical considering the surface pressure restrictions. Annular velocity for hole cleaning, bit hydraulics for drilling performance and equivalent circulating density (ECD) must be carefully managed and balanced to ensure the hole can be drilled and then maintained. Operators and industry research centres have spent several years improving the understanding of hole cleaning. There are now several internal oil company models and other proprietary programmes available to allow the well engineer to carefully plan the hydraulics and make sure the current best practice hole cleaning techniques are used.

Most extended reach wells have an inclination angle of between 70° and 80° in the tangent section of the well. At high inclination angles, the majority of the drillstring weight is supported by the side of the hole, as opposed to hanging from the block. Sufficient weight must be available from the vertical or lower angle hole section to allow the drillstring to be pushed into the hole in the high angle or horizontal section.

At extreme depths it becomes very difficult or impossible to overcome the friction forces present for drilling in oriented mode (slide drilling). Rotary steerable systems that control both inclination and azimuth while continuously rotating have been developed for such purposes with the added benefit of improving the hole cleaning. Other areas such as the clean-up phase and completion phase, where wellbore fluid types mean far greater friction, need careful planning and modelling. The drillstring must therefore be capable of resisting not only high torque when drilling, but should be capable of resisting buckling forces when present. High strength tubulars with high torque connections have been developed specifically for drilling and cleaning up extended reach wells and are readily available.

Torque and drag can best be controlled by design through selecting an optimum well trajectory and minimising dogleg severity while drilling. Remedial measures that can be used to reduce torque and drag include the use of non-rotating drillpipe protectors, lubricants and mud additives such as fibrous lost circulation material.

Other downhole problems, which have been overcome recently, include the problem of trying to obtain an MWD or LWD signal at extreme depth. Advances in signal generation technology and signal processing techniques have enabled the directional and logging information to be received successfully from along hole depths in excess of 30,000 ft.

Drilling extended reach wells from old platforms presents many challenges, however with sufficient effort in well engineering, selective rig upgrades and planning the problems can be overcome. It is possible to drill extended reach wells cost effectively and the advantages of drilling the wells

continued on P30...

Independents face hard choices

An economic slowdown and rising refinery-gate prices are posing some difficult questions to central and eastern European fuel retailers, writes *Mikhail Masokin*, Energy Analyst at Datamonitor, which recently published a review of the region's fuels retailing sector.*

The central and eastern European service station market is in a period of major transition. In most of the region's countries, the privatisation of fuels retailing is either complete or entering its final phase, creating a level playing field where western and local retailers compete for market share and customer loyalty. As competition intensifies, casualties will be inevitable.

To date, the region's service station market remains extremely fragmented, with none of the companies' volume shares exceeding 10% of the total, and some of the top-20 recording shares of less than 1%. In 1998, the 20 largest companies, local and foreign, together accounted for just over half of the market. This is set to change as the western oil majors continue to expand their presence and make life increasingly difficult for the region's independent retailers. In 1998, Shell, OMV, Statoil and BP together opened 360 new sites in the region, amounting to a 47% increase in their combined network.

Poland's giant CPN remains the region's leading retailer, with a volume share of 8.2%. However, Shell is catching up fast. Shell is the largest western oil company in the region, with 8% of volume sales in 1998. Together, the eight largest foreign retailers accounted for 22% of volume sales and 10% of the network. This is certain to continue to increase, possibly to as high as 30% of the regional market by 2003. High annual penetration rates by western companies are predicted both in those countries where their presence is already high, such as Estonia, as well as in those where it is currently limited, such as Bulgaria.

Figure 1 summarises the relative attractiveness of the central and eastern European markets from the points of view of predicted volume growth to 2003, and the current rate at which those markets are opening up to western retailers.

Market growth

In 1998, the volume of fuel sold by central and eastern European service stations (excluding those in Russia, Ukraine, Belarus, Yugoslavia, Bosnia-Herzegovina, Macedonia and Albania) amounted to 37.5bn litres. Within this, the Polish market recorded the highest volume of 14bn litres – more than 37% of the total. The Czech Republic and Hungary were in second and third positions, with 11.7% and 10.7%, respectively. As such, the top three markets together accounted for almost 60% of the total regional volume. 1998 was a difficult year for the region's retailers, with total volume sales decreasing by 0.2% on 1997. This compares very unfavourably with the 5.5% growth between 1996–97. There were three main reasons for this: a rise in refinery-gate prices, increased fuel taxation in many of the region's countries, and an unfavourable macroeconomic situation. Only four of the region's 12 countries experienced faster volume sales growth than in the previous year, with Hungary and Slovakia being the clear leaders. In contrast, Bulgaria, Moldova and Romania experienced the greatest reversal in growth rates (see **Figure 2**).

At the same time, regional networks continued to expand. In mid-1998 the total number of sites reached 15,840, a 3.7% increase on the previous year. Poland had 40% of the regional total, having grown by 9.7% on the previous year. This rate of expansion is unlikely to be sustainable in the longer term, but the composition of the network will change dramatically.

In the next five years, site number dynamics will be defined by a combination of two factors: service station construction and site closures. During the first years after the introduction of a market economy in the countries of central and eastern Europe, small independent retailers mushroomed. Due to their low capital base, their service stations tended to be small and technically unsophisticated. In addition, the national oil companies that had previously enjoyed a monopoly on fuel sales in their countries had many sites in inconvenient or low-demand locations. Consequently, a large proportion of service stations in central and eastern Europe are currently

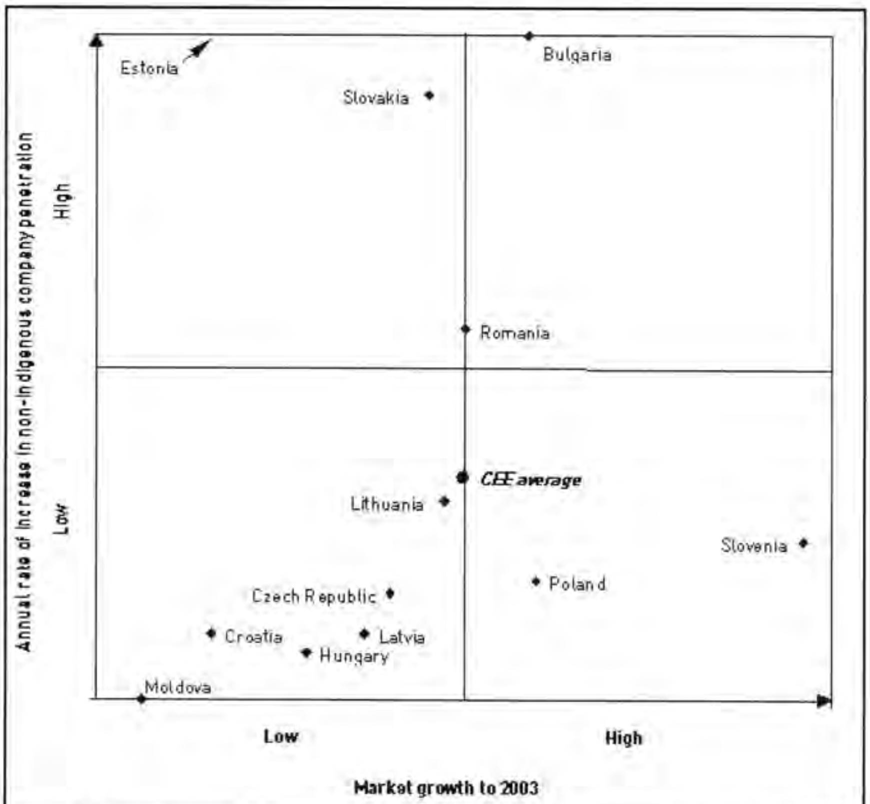

Figure 1: Growth potential within the central and eastern European market, 1998–2003
Source: Datamonitor

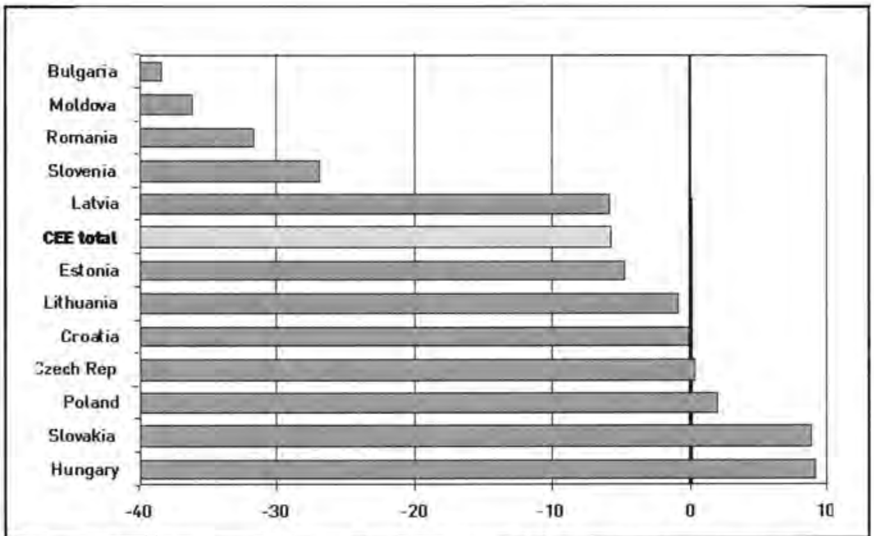

Figure 2: Change in annual volume growth rates from 1996–97 to 1997–98, % points
Source: Datamonitor

technically obsolete, too small for efficient operations, or inconveniently located. As market competition intensifies, such service stations are being closed down, and this process is expected to continue at a rapid pace.

In contrast, the major branded retailers, both indigenous and western, have been stepping up their site construction programmes. The newly-built sites tend to be technically advanced, EU fuel directive-compliant, and equipped with additional amenities such as a forecourt shop and car wash.

Developing the forecourt shop

With price competition among central and eastern European fuel retailers intensifying, forecourt offerings have been assuming increasing importance. The average proportion of non-fuel revenues of central and eastern European service stations is currently approximately 15%, but is expected to almost double by 2003. Western retailers will lead the way by seeking to replicate their western European averages, which in 1998 exceeded 25% of turnover and 40% of profit. However, the larger indigenous companies, such as INA and Mol, also have ambitious development programmes, aiming to equip every newly-built and redeveloped service station with a retail outlet. Higher margins on non-food items is one compelling reason why developing the forecourt shop will be a high priority; customer attraction and retention is another.

Western companies, such as Shell, Statoil, OMV and Neste, are having a major influence in the ongoing overhaul of fuel retailing in central and eastern Europe, and they will continue to set the standards for service, operating efficiency and revenue maximisation through non-fuel offerings.

Future trends

The central and eastern European service station industry is set to witness a combination of network rationalisation and development of non-fuel offerings. In addition, the privatisation of fuel retailing will soon be complete, with substantial stakes offered in such national oil companies as Romania's Petrom and Croatia's INA.

In the next five years, the volume of fuel sales in central and eastern Europe is estimated to grow by approximately 22%, reaching 45.5bn litres in 2003. This translates into an annualised growth rate of approximately 4% between 1998 and 2003. Slovenia is expected to have the highest growth rate of approximately 6.8% per annum. Moldova will grow slowest, at an average rate of 1.4% per annum. Virtually all of the remaining countries will have growth rates of between 2% and 4% over the period. Volume growth will be driven, as before, by increasing car ownership and, in some cases, rising living standards.

The size of the service station network in central and eastern Europe is expected to grow by approximately 30%, reaching a total of 20,560 sites in 2003. This translates into a 5.4% annualised rate from 1998–2003, thus outpacing volume growth. Therefore, despite ongoing network rationalisation, throughputs per site will continue to drop. In this, the region will also follow the western European trend (see **Figure 3**). Fastest network growth is expected in Poland, averaging approximately 10% per annum. Apart from Poland and Bulgaria, none of the countries are expected to exceed the 5% mark. At least two countries, Hungary and Moldova, will actually experience a decrease in the number of sites.

To sum up, the industry will experience increased price competition, high levels of network rationalisation, and further development of the non-fuel offering over the next five years. In this, the region will follow the trends that emerged in western Europe over the last five years. As the market becomes more competitive, both fuel price and the forecourt shop offering are set to be the most important factors across the region. In some of the countries in the region, fuel cards are also set to become a major tool in acquiring or defending market share, primarily within the commercial sector.

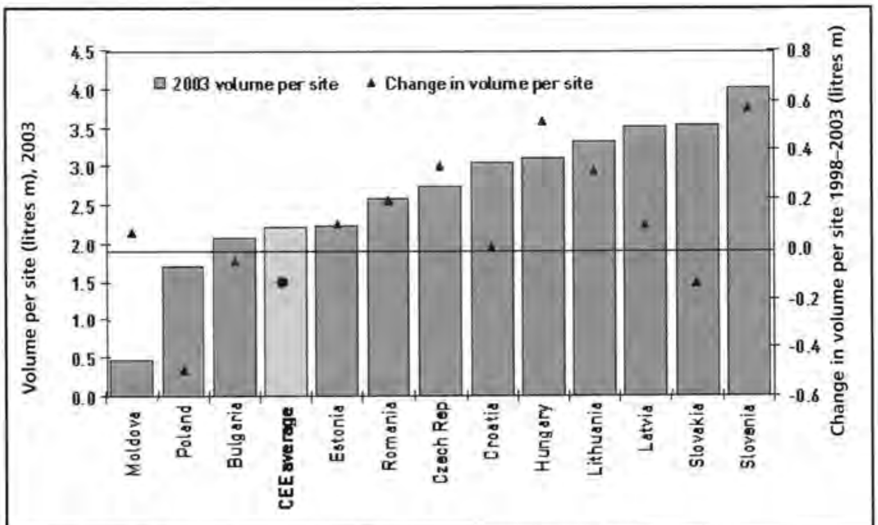

Figure 3: Central and eastern European service station network by country, 2003
Source: Datamonitor

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Rolling over brings relief

The North Sea has not been the easiest of places to make upstream profits recently, so the UK government's decision to allow companies to roll over any capital gains tax (CGT) liability arising from the transfer and sale of offshore licence interests has been widely welcomed, writes *Chris Chew*.

The North Sea oil and gas industry was specifically excluded from the tax relief for technical reasons when the CGT rules were overhauled in 1987. This new concession – which essentially brings the North Sea back into line with other industries – will allow companies who sell a UK offshore oil licence to reinvest in another qualifying asset within three years without triggering an automatic liability to CGT. The tax arising on a gain can therefore be deferred indefinitely, or until the company ceases to operate in the North Sea.

The industry, mainly in the shape of UKOOA (UK Offshore Operators Association), had been lobbying for this change for some years. The main concern was that, with the increasing maturity of the North Sea, the ability to consolidate smaller fields into blocks large enough to justify higher levels of investment was being impeded by CGT considerations. The potential tax liability was clearly a disincentive to companies attempting to rationalise their asset portfolios. UKOOA, although unable to quantify the detrimental effect of CGT, has become aware of a number of deals that ultimately failed, in which tax was an important factor.

Potential impact

Wood Mackenzie, in its analysis of the change in the tax rules, has identified the southern gas basin, the northern North Sea, Liverpool Bay and the outer Moray Firth as areas of potential restructuring where the removal of the tax penalty could have an impact. The company also believes that the move will simplify the decision-making process within companies heavily involved in merger activity – such as BP Amoco, Mobil Exxon and TotalFina – as the removal of the distortion due to tax considerations means that decisions can now be made on straight commercial grounds.

The overall effect of this change, according to Lasmo, should mean 'a more sensible value for North Sea assets', while UKOOA commented that 'the increased freedom to rationalise investment portfolios will lead to reduced production costs and enhance the industries' competitiveness'.

Two questions remain, however: what is the likely impact on the industry's costs, and how rapidly are the tax changes likely to have an effect?

Assessing the costs

In national terms the money amounts at stake appear to be small. The UK Treasury is likely to lose between £20mn and £25m a year in tax revenue but, as Wood Mackenzie points out, the amount is small precisely because companies are unwilling to trade assets more actively. Quantifying the benefits to the industry, however, is much more difficult. UKOOA believes that the consolidation of small holdings into larger, more economically viable units should, eventually, mean lower operating costs but feels that it is still too early to be able to put reliable numbers on the concession. UKOOA also makes the point that the tax change will stimulate investment in other areas of the North Sea. This will yield further tax revenues, resulting in 'a win–win situation for both the government and industry'.

The Treasury informally estimates that the industry could benefit by some £15mn to £20mn a year in terms of operational savings, but it believes that the total benefits go far beyond the immediate cash savings. This was summed up by Barbara Roche, the Financial Secretary to the Treasury, who, when announcing the change, said that the measure 'will help safeguard the industry's future and with it the employment prospects for people working on the platforms and in associated industries' because the move will 'stimulate prospects having a positive effect on employment while at the same time improving efficiency where operating costs are set to fall'.

Delayed impact

The impact on timing is equally difficult to assess. UKOOA sees the move as evolutionary rather than revolutionary, as it will take some time for the effect of the tax change to work through to companies' capital spending plans. The high level of merger activity in the industry, however, will inevitably increase the volume of assets being traded and, if the tax change leads to greater transparency and a more accurate basis for pricing assets, this will generate a greater volume of activity.

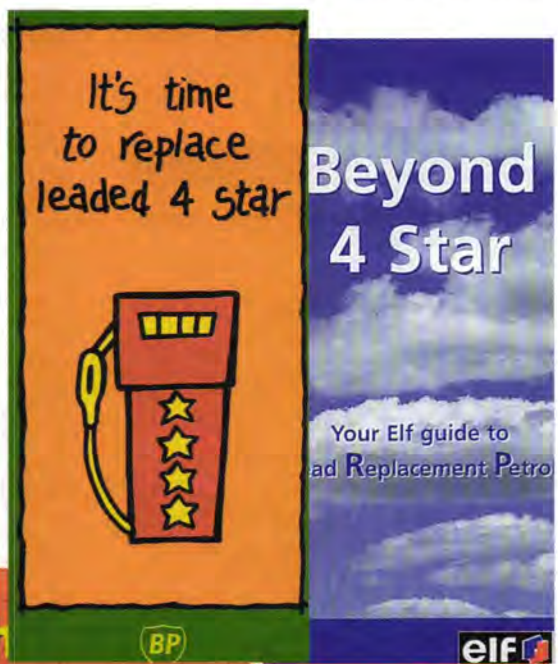
For smaller companies in particular, assuming that they have a large exposure to the UK North Sea, there are likely to be two significant effects. The first is that, with companies no longer locked-in by tax considerations, they will have a much greater freedom to change strategy by reshaping their portfolios. Secondly, a more active market for assets will mean not only a more efficient and transparent pricing mechanism, and thus greater confidence when taking investment decisions, but also provide wider opportunities for participation and investment. In short, this particular roll-over could bring considerable relief. ●

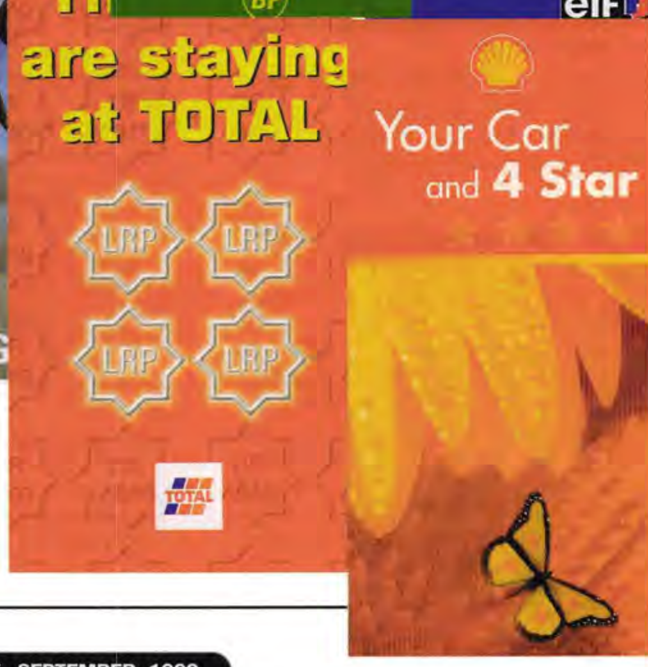
Looking to a lead-free future

The use of leaded petrol is being phased out across Europe in a bid to reduce pollution from road traffic and improve air quality.* It will be banned from sale on UK forecourts from 1 January 2000. *Kim Jackson* looks at the alternatives that are available, including lead replacement petrol (LRP), which many UK fuel retailers are introducing to their sites for the first time this month.

Tetryl-ethyl lead (TEL), or 'lead' as it is more commonly known, was first added to petrol in the 1920s in order to improve octane ratings. It also offered the additional benefit of lubricating the valve seats of the vehicle engine, preventing localised spot welding of 'soft' valve seats (made of cast iron or unhardened steel) and protecting the valve stem from wear and potential seizure, and so reducing the likelihood of 'valve burn'.

Increasing health and environmental concerns since the 1970s resulted in the amount of lead additive incorporated into petrol being progressively reduced to today's maximum level of 0.15 g/l. A minimum content of lead of 0.05 g/l is also specified in the British Standard for leaded petrol, BS4040. A lead content of 0.05 g/l is the minimum level specified to inhibit valve seat recession – a process by which non-hardened valve seats that are not sufficiently lubricated and protected by lead oxide and lead sulphate deposits are severely damaged over time through localised welding and attrition. If the valve seats recede by more than the pre-set valve clearances, combustion gases will escape and valve burn will result. It should be noted, however, that the level of vulnerability to valve seat recession varies enormously – vehicle maintenance, vehicle use, engine speed and the owner's driving style all have an effect on the critical parameter which is internal engine temperature.





Oil companies are now disseminating their own information leaflets from service stations

Unleaded fuel was first introduced in the UK in 1986, prompted by the development of the three-way catalytic converter. Designed to reduce exhaust emissions of hydrocarbons (HC), carbon monoxide (CO) and nitrogen oxides (NO_x) by up to 90%, catalytic converters are 'poisoned' by lead additive and need to run on unleaded petrol. Concern about the impact of lead to health, in particular children, also encouraged the introduction of unleaded fuel. From 1990, all new cars sold in the UK had to be capable of running on unleaded fuel and were fitted with hardened valve seats which do not require protection from lead additive. From 1993 all new cars were required to be fitted with catalytic converters and run on Eurograde unleaded (95 RON).

As a result of these developments, the size of the car parc requiring leaded fuel in the UK has diminished considerably. It is estimated that of the 21mn-plus vehicles on the UK's roads today, only 5.3mn will be running on leaded fuel by the end of 1999. Although this represents about 28% of the car parc, latest figures indicate that in the first four months of 1999, leaded petrol only accounted for 16.4% of total petrol sales in the UK. Of these 5.3mn vehicles, an estimated 3mn do not actually need the protection of lead additive and are capable of switching from leaded to the use of unleaded petrol, either directly or following adjustment of the ignition timing in order to avoid 'pinking' as a result of the loss of two octane numbers by changing fuel type. The remaining 2.3mn vehicles have 'soft' valve seats and require the protection of lead or an alternative.

There are primarily two categories of vehicle within this 'at risk' sector:

(1) older vehicles (typically over 10 years old and ranging in condition from the well maintained to old 'bangers'); and

Product (contact)	Chemistry	Dose rate
Millers VSP Plus* (Millers Oil: 0800 281053)	Manganese (Mn)	250 ml/40 litres petrol (6.25 ml/l) (equiv. to 36 mg Mn per litre fuel)
(NB. Claimed to also boost octane by 2.1 octane numbers on average)		
Red Line Lead Substitute* (Delta Oil: 01476 861195)	Sodium (Na)	8 ml/10 litres petrol (0.8 ml/l) (equiv. n/a)
Superblend Zero Lead* (Superblend Lubricants: 0116 291 1700)	Potassium (K)	500 ml/150 litres petrol (3.3 ml/l) (equiv. to 10–11 ppm K per litre fuel)
Valvemaster* (Associated Octel: 01908 273606) (see *Petroleum Review*, November 1998)	Phosphorus (P)	600 ppm Valvemaster per litre fuel (equiv. to 30 ppm P per litre fuel)
Valvemaster Plus	Phosphorus plus Ferrocene	600 ppm Valvemaster Plus per litre fuel (equiv. to 30 ppm P per litre fuel)
(NB. Claimed to also boost octane by up to two numbers)		
Valve-Guard (V-Guard) (RE Speciality Chemicals : 0800 917 4321) (see *Petroleum Review*, August 1998)	Potassium (K)	10 ml/20 litres petrol (0.5 ml/l) (equiv. to 8 ppm K per litre fuel)

** Carry FBHVC endorsement*

Table 1: Examples of some bottled additives currently available on the UK market

(2) the classic/historic vehicle (typically over 20 years old but usually extremely well maintained).

Of these two groups, classic car owners are probably better informed regarding alternatives to the use of unleaded petrol – primarily through the work of the various car clubs and associations. The drivers of older vehicles are less well informed, and, as a result, are potentially the most at risk.

However, considerably more information has been made available in recent months. The DETR has produced three leaflets on the topic (available from most service stations, MOT stations, libraries and citizens advice bureaus), while motoring organisations such as the AA and RAC have produced their own information 'packs' for members outlining the current position and what alternatives are available. The oil companies are also disseminating their own leaflets from service stations, while some, such as BP, Texaco, Shell and Elf have also set up customer telephone 'hotlines'. Indeed, Esso and Elf both launched LRP at a limited number of their sites on 30 July this year. The DVLA is sending out information within its mailings. Most recently, UKPIA and the DETR launched a two-week newspaper awareness advertising campaign, beginning on 4 August 1999, giving motorists clear guidelines on how to prepare the the phase-out of leaded fuel. The DETR also provides guidance via its website which can be found at **www.environment.detr.gov.uk/unleaded/index.htm**

Alternative options

A number of alternatives to the use of leaded fuel are available to those motorists needing to protect their engines from valve seat recession:

- lead replacement petrol (LRP)
- dosing unleaded petrol with a 'bottled' anti-wear additive (which may be packaged in a disposable, pre-measured syringe applicator or a calibrated bottle)
- in-fuel/in-tank devices
- biding time – ie, run on LRP and see what happens
- engine conversion – fitting hard-alloy valve seat inserts into the cylinder head (or engine block in the case of side-valves).

Lead replacement petrol (LRP)

LRP will probably prove the most popular option with the motorist as it is the simplest alternative to use. It is to be marketed on the forecourt in the same way that leaded fuel has been in the past, from the same pump, using the same red colour-coded nozzle covers and having the same 97 RON octane rating. As *Petroleum Review* went to press, it was not entirely clear what price LRP will retail at once rolled out nationwide. The Frost Group, which is already retailing Unleaded 4-star (LRP) from a number of its Save branded forecourts, is currently pricing it at a similar level to leaded 4-star, while BP Oil states that it expects the price to 'probably be similar to the leaded 4-star it replaces', and Esso says 'no more expensive than leaded 4-star'. Pump prices are also likely to be impacted by a 3.7 p/l reduction on the duty levied on LRP from 1 October 1999.

There is also the 'assurance' that the dosing of the additive blended by the fuel supplier is probably more reliable than the motorist adding it to the tank of petrol when filling up. However, it should be noted that many of the bottled additive packagings are sold either in pre-measured single-dose applicators or clearly marked in order to facilitate accurate dosing, providing the user follows the instructions properly.

Leaded fuel for special cases

Although leaded petrol is to be banned from sale on UK forecourts from 1 January 2000, there is a derogation in the EU Directive that stipulates that a small amount of leaded fuel will still be available (but not from UK forecourts) to meet the needs of 'special interest groups', such as classic car clubs and the racing fraternity.

The exemption is on the basis that volumes do not exceed 0.5% of total fuel sales in Europe and that the government of each Member State undertakes to ensure that the fuel does actually go to whom it should. Approximately 28mn gallons of leaded fuel is expected to be made available in the UK. It is unlikely to be retailed at the same price as leaded fuel is today (approximately £3.54 per gallon), and the UK Federation of British Historic Vehicle Clubs (FBHVC) estimates it may cost as much as £5 per gallon.

Two minor fuel producers have expressed an interest in supplying this niche market but distribution of the fuel and geographical spread, however, remain sticking points. According to FBHVC, there had been talk of whether airfields might be interested in dispensing the leaded fuel, or if the fuel could be sold to interested parties in 40-litre drums. However, stringent storage regulations have scuppered both proposals.

The FBHVC is currently working with the petroleum industry and government to establish a distribution network. It is particularly concerned that there should be more than one supplier. However, the volumes concerned may not be large enough to support too many players in this niche market.

The Frost Group is already retailing unleaded 4-star (LRP) from a number of its Save branded forecourts in the UK

Four chemistries are likely to be used in LRP: potassium, phosphorus, manganese and sodium, of which potassium has been used most in overseas markets which have banned leaded fuel already (see box p21). There is some evidence that the mixing of two or more metal-based additives can, depending on concentrations and engine temperatures, produce lower melting point sulphate mixtures (termed eutectics), allowing 'hot corrosion' to take place at lower temperatures, increasing the potential for engine wear and hot corrosion damage. This may only be an issue with sodium which forms lower melting point alloys.

According to the Retail Motor Industry Federation (RMI), its sponsored tests indicate that lead is better than phosphorus at preventing corrosive wear at high temperatures and resisting hot corrosion of key petrol engine parts, which in turn is better than sodium, potassium or manganese. Ethyl Corporation, however, comments that such a ranking is 'incorrect' stating that while lead is frequently considered superior to other metals in providing valve seat recession protection, it is 'not necessarily so' in the case of resisting hot corrosion. 'The perception of lead providing superior VSR protection usually overlooks the concentration effect, ie that lead has been traditionally used at treat levels much greater than is possible with the alternatives currently considered viable,' comments Ethyl. 'The point that the higher the treat level of metallic additive the better the protection, particularly in extreme conditions, has been demonstrated in work undertaken by Ethyl and others such as Shell.' [The company emphasises that this comment is subject to the qualification of observing the recommended upper treatment limits of any additive to avoid known detrimental side effects.]

Ethyl states that its manganese-based additive, MMT, has been used in the US as a lead replacement additive for a number of years 'with no recorded instance of corrosive wear or hot corrosion occurring'. It claims recent scientific studies have shown that, at the temperatures typically experienced by valves and valve seats, MMT does not form the sulphates which are the primary cause of hot corrosion problems. Furthermore, it states that MMT, unlike the other additives, does not give rise to the formation of lower temperature eutectics that would fall into the critical temperature regime if mixed with other metals.

Associated Octel, manufacturer of the phosphorus-based 'Valvemaster' additive, also points out that its tests have shown 'no corrosion effect caused by phosphorus', and claims that phosphorus provides 'superior valve seat protection' compared with other currently available additive products.

Potassium, like the other valve seat recession protection additives, appears less effective than lead. Nevertheless, engine tests and widespread commercial experience have proven it adequate protection for all normal driving conditions.

Setting standards

We understand the British Standards Institute (BSI) had been working on establishing a standard for LRP. However, work was postponed pending the outcome of a court case brought against the RMI by the Frost Group. The fuel retailer, which launched LRP based on a sodium additive at a number of its UK service stations in the UK in July 1995, is now exclusively using potassium as the additive. The company's LRP is marketed as 'Unleaded 4 star' (see photo) from some of its Save branded outlets in the UK.

The RMI argued that it had significant evidence that sodium (and potassium to a lesser extent) had resulted in 'hot corrosion', particularly on exhaust valve seats and turbochargers, in Sweden. The Frost Group vigorously disputed the RMI's allegations, stating that the Association was not presenting a truely representative picture as it had looked solely at the Swedish market and ignored all other countries in the world successfully using LRP at the time. The case was settled out of court.

Although work on the standard resumed once the case was settled out of court, it was abandoned in June this year 'owing to a lack of consensus' among the Committee participants.

'The lack of a British Standard is unfortunate, but not illegal,' comments R James Frost, Chairman of the Frost Group. 'It is unfortunate because there has been a lack of publicity that would have ensued from the grant of a British Standard... it would have made explanations to the customers easier...it would have given customers some reassurance... and would have made life easier for the petrol station operator and operator's staff.'

However, Peter Barlow, the Environment, Health and Safety Advisor to the RMI, argues that the lack of a British Standard could, perversely, turn out to be a beneficial turn of events for the UK motorist. He points out that the oil companies will now have to take particular care to retail an LRP that will be compatible across the entire distribution network as there will be no British Standard to 'hide behind' if problems arise. Originally, one standard allowing three additives – phosphorus, potassium and manganese – was being developed. Sodium was deleted from the standard following BSI concerns due to the issues in Sweden. The RMI had con-

IP test methods

At the request of British Standards, the Institute of Petroleum has developed new test methods for the determination of the potassium, phosphorus and manganese content in petrol. These were to be called up in the LRP specification, work on which has now ceased (see main article).

The phosphorus and manganese methods are based on ASTM methods, have been adapted and will be published with their permission. The potassium method is based on a Shell Research and Technology Centre in-house method adapted for use as an IP method by the IP's Inorganic Test Methods Panel. On publication, the three test methods will be accorded the status of British Standards and will form part of the BS 2000 Series published by the IP. This work will be completed in less than six months and shows how the IP can respond swiftly to industry's needs.

cerns that, unless the type of additive used was made clear by pump labelling, motorists could easily end up mixing chemistries. The DETR was extremely disappointed that the standard had to be abandoned but says that it is not overly concerned by the lack of a British Standard, citing that LRP has been marketed without an industry standard in Germany, Austria, Switzerland, Denmark and Finland for a number of years without problems.

The Frost Group has not been the only company to look at retailing LRP in the UK well ahead of the EU Directive banning the sale of leaded fuel. Supermarket chain Asda, Kuwait Petroleum and TOTAL also tested the market around 1996. However, according to Dr Jim Laxton – a chemical consultant associated with ITS Testing Services and a Fuels Adviser to international motor sport governing bodies – the higher tax imposed on super unleaded fuel (the only commercial grade of petrol at the time available as a basestock for LRP) by the UK government reduced the incentive for the largescale retailing of LRP. He emphasises that it was this fiscal disincentive that hampered the take-up of LRP and not any technical problems associated with the fuel or its additives.

Based on a poll of service station fuel suppliers by *Petroleum Review*, it seems that most have chosen to use potassium as the additive for their LRP, probably at a dosage of around 10 ppm.

Bottled anti-wear additives

While the major oil companies plan to sell LRP at all their sites, some of the smaller independents, particularly in rural areas, may not have sufficient underground storage to stock the product or be able to generate sufficient sales volumes to warrant a dedicated LRP pump. In this case, bottled additives may prove to be the answer.

Bottled additives have been used on the Continent (for example, Germany, Austria, Switzerland) and elsewhere in the world (New Zealand) for a number of years. As with LRP, four different chemistries are currently used: potassium, phosphorus, manganese and sodium. Some examples of the products currently available on the UK market are listed in **Table 1**.

No British standards exist for bottled additives, and, at present, there are no plans to establish any or to adopt the Australian standard (AS 4430.1-1996) which is understood to be the sole independent standard covering such products anywhere in the world. That said, some organisations have conducted independent tests on the various products. In 1998, for example, the UK Federation of British Historic Vehicle Clubs (FBHVC) (backed by the RAC) invited 40 suppliers of bottled additives and devices to put samples forward for testing – at their own expense – which, on a positive result, would then receive the FBHVC's stamp of approval.

Ten additives and two devices were submitted for testing. The relatively low number of products finally submitted was attributed, in part, to some products being made by the same manufacturer and some manufacturers not accepting the validity of the testing procedure.

The test procedure centred on the use of a Rover A-series 1275cc engine – used in a number of classic cars and known to be susceptible to valve seat recession. Each product was tested on the same short engine, but starting with a new cylinder head each time. The engine was given a bottom-end overhaul halfway through the testing programme. The tests were independently carried out by the Motor Industry Research Association (MIRA).

The RMI comments that by conducting engine bench tests, or road trials, with reconditioned cylinder heads and rebuilt engines with good cooling capability in proper test house conditions does not truly reflect the performance of anti-wear additives in practice. It believes that the higher valve and valve seat temperatures of the less well-maintained vehicle would provide a more severe test of additive performance.

The testing programme consisted of measuring valve clearances at the beginning and at regular, predetermined intervals. The engine was bedded in for an hour and then run for 50 hours at 3,800 rpm (low load), followed by 20 hours at 5,500 rpm (high load). A 'pass' was taken as being where no significant recession of the exhaust valves occurred throughout all stages of the test. A 'fail' occurred when cumulative recession exceeded 0.3 mm in the full 70-hour test. A fail also occurred if cumulative recession exceeded 0.15 mm during the 50-hour, 3,800-rpm phase of the 70-hour test programme.

Leaded, low leaded and unleaded fuel, without additive, were also tested as references. Leaded petrol resulted in negligible wear (0.001 mm) over the test period, while unleaded resulted in 1 mm of wear. No LRP product was tested – the FBHVC was 'disappointed' by this, and commented that even though no LRP was being produced for sale at the time of testing, it should have been possible to 'come up with a close approximation suitable for testing purposes'.

Of those products tested, the devices failed and only four bottled additives fulfilled the pass criteria: Millers VSP-Plus, Red Line Lead Substitute, Superblend 12/Zero Lead 2000 and Valvemaster (see **Table 1**).

'Bottled' anti-wear additives are packaged either in a calibrated bottle (right) or a disposable, pre-measured syringe applicator (above)

Consequently, these four products are entitled to carry the FBHVC endorsement, provided that they are marketed in exactly the same form in which they were tested. (Note: FBHVC states that nothing in that endorsement implies any liability on its part or MIRA's for any damage or costs incurred following the use of the endorsed product.) A limited batch of further testing is currently under consideration.

Stick with it

Once LRP or a bottled additive has been chosen, the advice of industry experts is that it is best to stick with that particular choice rather than swapping between chemistries. If the bottled additive route is chosen, it should be used at every refuelling as, unlike lead, there is no 'memory' effect. However, occasional leaded and LRP fills, for example during the changeover period, should not cause any problems.

Oil company choice

On the whole, most of the service station operators appear to be planning to sell LRP rather than bottled additives. Only two companies contacted by *Petroleum Review* plan to sell both products from the beginning – Elf and Safeway – although Texaco states that the sale of bottled additives from certain individual shops has not been discounted if the shop operator believes that sufficient revenue can be generated.

Elf also launched a support service at selected service stations in London when it announced that it would be retailing the Valve-Guard lead replacement additive at its sites earlier this year (see *Petroleum Review*, May 1999). Together with Hometune Services (a Kwik-Fit company), the oil company will provide motorists with free advice as to whether their vehicles can run on unleaded petrol with or without requiring retuning and if use of the Valve-Guard additive is necessary to protect the engine. The advice is free, although there is a charge of £20 plus VAT if an adjustment of ignition timing is required.

Converting the engine by fitting hardened valve seat inserts is the most expensive of the alternative options

The balance between LRP and bottled additive sales may change if demand for the latter proves to be higher than first anticipated. In addition, because the car parc requiring lead replacement petrol is a tapering market as older cars are scrapped, it is possible that once the sale of LRP is no longer economically attractive to the service station operators, bottled additives will become the main recourse for the motorist.

Devices

A number of in-fuel/in-tank devices based on the use of magnets and/or metals (in particular tin) are also on the market, and are claimed to allow the use of unleaded petrol in otherwise unconverted cars. However, the science behind these claims has yet to be established and motoring organisations such as the AA and RAC, as well as a number of car clubs, are advising their members to steer well clear of such devices.

Biding time

Doing nothing is not really an option. Using LRP and checking tappet clearances, especially if the engine is used for towing or prolonged motorway driving, is the 'fail-safe' approach. If compression is lost on a cylinder or the valve clearances disappear, the alternative of going to hardened valve seats is the only option if the driving regime continues.

Engine conversion

Converting the engine by fitting hardened valve seat inserts is the most expensive of the alternative options – costing around £300 to convert a 'simple' engine such as a Morris Minor. However, once done, it provides peace of mind as the motorist need not worry about choosing between LRP or a particular bottled additive, or be concerned over the geographical availability of the chosen product.

Not all engines can be converted, however, either because the seats are very close together or, in the case of non-detachable cylinder heads, because access is difficult.

Road ahead

If, like me, you are currently running a car on leaded petrol, you need to decide soon which road you are going to follow. Be it LRP, bottled additives, or an engine conversion, each person's situation will be unique, and the decision based on personal choice balancing convenience, cost and piece of mind. I, for one, have an unleaded cylinder head sitting in the hallway at home – all I have to do now is find the time to fit it to my Spitfire... along with a new differential, shock absorbers and gearbox. Whoever said owning a 'classic' car was fun?

European position

The move to end the use of leaded petrol in cars across the European Union by the end of the year is almost complete, with uncertainty remaining in only three of the 15 Member States, reports *Gary Spinks*.

Bans on forecourt sales of leaded fuel are already in force in Austria, Belgium, Denmark, Finland, Germany, Luxembourg, the Netherlands, Portugal and Sweden, with the UK, France and Ireland planning to phase out the fuel by the deadline.

Applications for a derogation from the EU Directive banning the sale of leaded fuel in Member States from 1 January 2000 can be made, but only Spain had done so as *Petroleum Review* went to press. However, both Italy and Greece may follow suit – their applications needed to be made to the European Commission by the end of August 1999.

As indicated in the main article, in order meet the requirements of the fuel quality Directive, countries may introduce a lead-free lead replacement petrol (LRP), which motorists can fill up with direct from pumps, or make available bottled additives which drivers must add to the fuel tank themselves.

The countries which use, or will use, LRP are Belgium, Denmark, France, Ireland, the Netherlands and the UK. Member States opting for bottled additives include Austria, Germany and Sweden.

Nations providing a combination of both LRP and bottled additives are Finland, Luxembourg and Portugal. Other countries may join the list if oil companies decide to extend development along this route.

A European Petroleum Industries Association spokesman told *Petroleum Review*: 'Most countries appear to have gone for either an LRP or bottled additive. Some use both. Finland uses bottles generally, but at unmanned forecourts an LRP blend is available. On the whole there should be few problems created for motorists by the changes.'

* *The EC's Fuel Quality Directive (98/78/EC) calls not only for the removal of lead additive, but also a reduction in the permitted quantities of certain fuel components in unleaded petrol and diesel fuel, such as benzene and sulfur, which have an adverse effect on the environment. The Directive is part of a package of 'Auto Oil' measures aimed at producing significant reductions in emissions from all classes of vehicles.*

One-stop-shop for subsea well intervention

As the number of subsea wells used to exploit oil and gas discoveries started to grow in the early 1980s, well managers became concerned that conventional drilling rigs were not cost-effective for routine well operations, particularly well logging. In response to this demand for a cost-effective solution to the problem of accessing subsea wells, Coflexip Stena Offshore (CSO) constructed the *CSO Seawell*. *Eamonn McGennis* of Coflexip outlines the services offered by the vessel and its role in the decommissioning of subsea fields.

The *CSO Seawell,* even to this day, remains unique as it is the world's only active dynamically positioned (DP) light subsea well intervention vessel. The vessel was purpose-built for subsea well operations by combining a large DP hull, a fully rated hyperbaric dive system and a compact well operations derrick. The heart of the vessel is the derrick which is used to run the CSO/Camco joint venture Subsea Intervention Lubricator (SIL). The SIL is lowered onto subsea trees which then allows downhole tools up to five-inches in diameter to be run in and out of the hole under pressure.

Vessel operations

The *CSO Seawell* provides a variety of subsea well intervention services:

- *Well logging* The *CSO Seawell* and SIL were originally designed to provide well logging services. This is where an electronic tool is lowered into the production tubing and run down into the reservoir from where it makes various measurements to establish information such as fluids in place, porosity and permeability. CSO ran its first subsea well logging operation in 1987.
- *DHSVs* In case of a sudden leak on the subsea christmas tree, most subsea wells are fitted with downhole safety valves (DHSVs) which are supposed to shut-in to avoid any oil spill. On occasion, these valves have failed in the closed position and the *CSO Seawell* has been used to replace the valve or run an insert as appropriate.
- *Gas lift valves* Oil output can be improved in many wells by injecting gas into the production tubing to reduce the density of the fluid. As production drops the gas needs to be injected further down the well to maintain flow. This activity has been undertaken by CSO since 1988.
- *Perforating* Once the logging tool establishes a description of the reservoir it may be necessary to perforate holes in the metal casing used to seal the reservoir. This will allow trapped oil to flow into the production tubing. These perforating guns have sophisticated safety systems to avoid premature firing on the surface. CSO performed its first subsea perforation job in 1988.
- *Setting plugs* In older wells the water level usually rises as the oil is produced. This can be a problem if the original perforations are too low. To reduce the water, cut mechanical plugs can be set to block off the lower perforations. These packers can be up to 5 inches in diameter when run into the tubing, but can be inflated up to 10 inches when downhole. Plugs can also be used to temporarily secure a well or to act as a foundation for cement plugs. CSO has offered this as a regular service since 1991.
- *Pumping* The *CSO Seawell* is equipped with four high-pressure oil well pumps. These are mostly used for pumping cement into wells to shut off permeable zones. This can be for water shut-off to boost production or to seal hydrocarbon zones for well decommissioning. Cement is usually pumped directly through the production tubing. CSO completed its first DP subsea tree recovery in 1993.
- *Tree operations* As the *CSO Seawell* can set mechanical plugs down in the well it is possible to secure both the production and annular tubing allowing the subsea tree to be removed for repair or modification. Once the new tree is put back in place the mechanical plugs are removed and the well can be

CSO Seawell

Coiled tubing extension frame suspended in derrick

brought back onstream. CSO completed its first subsea tree changeout in 1995.

- *Coiled tubing* As wells become more and more deviated it is difficult to get conventional wireline tools to the bottom due to the loss of gravitational pull. In this situation, the tools need to be pushed to the bottom and to meet this need CSO has developed a coiled tubing (CT) service in association with Schlumberger Dowell and Camco. The *CSO Seawell* carried out the world's first CT intervention from a DP vessel in 1997.

Subsea field decommissioning

CSO has been involved in all North Sea subsea field decommissioning projects since the very first field abandonment of the Crawford field for Hamilton in 1991. The *CSO Seawell* has been the only method used in the UKCS for the plugging and abandonment of all production and injection wells in decommissioned subsea fields since 1993 and it is this ability to remove live subsea wells that has become the foundation of the company's subsea field decommissioning capability.

The importance of efficient well abandonment techniques became apparent during the very first field-decommissioning project where the subsea wells were plugged using a DP drill rig. Technical problems with the rig and the fact that it needed dive support from the *CSO Constructor* demonstrated that this was not an ideal solution. This led to the development of effective well plugging procedures that could be deployed directly from the *CSO Seawell.*

These procedures were first used on the Argyll field for Hamilton in 1993. The basic technique relies on the deployment of the SIL onto the subsea tree, which allows wireline access into the well. The wireline can deploy perforating guns and set plugs to prepare the well for final cementing which is pumped down through the production tubing with returns up the annulus.

Cutting costs

As most of the cost of a subsea field lies in the actual subsea wells themselves, the ability to plug and secure the wells without the expense of a drilling rig is a huge advantage. The fact that the *CSO Seawell* has a diving capability also allows a lot of preparation work to be done on other subsea equipment ready for final field removal. The flexibility and efficiency of the vessel enabled CSO to secure the contract for BP Amoco's first ever field decommissioning project – the Donan field – in 1998. Amerada Hess also selected the *CSO Seawell* for the decommissioning of the Durward and Dauntless fields this year as the lump sum approach to the work by CSO eliminated the risks usually posed by open-ended drilling rig programmes.

Tree on deck

Crew running riser

Future innovation

Recognising the need for continuous innovation and cost reduction in an age of depressed oil prices and cut- backs in operational expenditure, CSO is now developing a well clean-up capability, due to be introduced in spring 2000. This service will augment its CT capability and allow the removal and disposal of treatment chemicals, milling and perforating debris and produced hydrocarbons, etc, from the well following well service and stimulation activities. This will reduce the customer's risk, the risk of damage to the formation and reduce costs. It will also add the *CSO Seawell*'s capability and provide the opportunity to conduct multi-well campaigns offering significant benefits and cost savings to customers.

West of Shetlands deepsea development

The Foinaven and Schiehallion fields are currently producing around 150,000 b/d of oil in the Atlantic Frontier, West of Shetlands. Achieving this production has been a monumental struggle and future prospects were not looking too bright. However, things could be about to pick up, writes *Jeff Crook.*

The *Schiehallion* FPSO is capable of handling 154,000 b/d of oil

The sea conditions in the Atlantic Frontier (also known as the Atlantic Margin) are more treacherous than the North Sea – 27-metre waves recorded during a recent storm. The ocean depths also mean that it is not possible to use commercial diving for seabed operations. Vast sums of money have been invested in this 'exciting new oil play' but recent events in this area have not been very cheering for the oil companies.

Postponed projects

The Clair field development – the largest oil field discovered in the region to date with an estimated 5bn barrels of oil in place (larger than most North Sea fields) – ground to a halt last year. The field partners were close to sanctioning a fixed platform development, but the low price of crude at that time was among a number of factors that forced a rethink. A major joint industry initiative known as Aurora, which aimed to build a gas transport infrastructure for fields in the Atlantic Frontier region, was another casualty of the economic climate prevailing at the time (see *Petroleum Review*, March 1998).

Discovered in 1977, the Clair field lies in reasonably shallow water just 75 km west of the Shetlands. The reservoir is complex and has poor production characteristics. Sentiment for the project was not improved by a series of delays to Foinaven and an incident in which the *Schiehallion* FPSO suffered bow damage during a severe storm towards the end of last year. The latter incident provided ammunition for the environmental group Greenpeace which has been running a campaign to halt exploration in the Atlantic Frontier region.

The good news...

Not all is doom and gloom, however. There was some good news for the industry when the Foreign Office Minister Tony Lloyd signed the UK/Faroes Maritime Boundary Agreement on 18 May 1999 which will allow the governments on both sides of the boundary to license areas with strong hydrocarbon potential.

Of course oil companies need extraordinary patience, strong nerves and deep pockets to open up a new region as demanding as the Atlantic Frontier. BP Amoco says that exploration in the UK sector of the Faroes/Shetland Trough began in 1972 and it took 20 years and 100 exploration and appraisal wells before the discovery of Foinaven, the first commercially viable find. The development of this field was a considerable technical achievement.

Foinaven first

After discovery of the field a massive 3D seismic programme covering 2,050 km was carried out to gain an understanding of the geology around the Foinaven reservoir. BP subsequently undertook a programme of appraisal drilling and this was followed by an extended well test to allow the development plan to be assessed and well positions optimised.

The government gave approval for a £600mn fast-track development scheme in 1994. First oil was due to flow by early 1996. Many observers thought the schedule very tight given the enormous technical challenges, and the programme ultimately proved over-ambitious. First oil was not achieved until November 1997, around 18 months behind the original schedule.

The Foinaven field lies in 500 metres of water on the edge of the continental shelf 190 km to the west of the Shetland Islands. The development plan involves a steel-hulled FPSO connected to subsea wells. Although this arrangement has been widely used in the North Sea, Foinaven represented the first time that this approach had been used in the UK sector when the seabed could not be reached by commercial divers.

As diving was ruled out, the project was highly dependent on the use of remote operated vehicles (ROVs) to perform all the subsea installation and intervention tasks. The ROV operations presented a challenge of their own. Subsea currents flow at up to 2 metres per second while the support vessel can be tossed around by Atlantic waves up to 20 metres high. There were a large number of pipe connections to be made on the seabed due to the well cluster arrangement adopted for the project and the geography of the reservoir.

The Foinaven reservoir extends over a relatively large area (16 km by 10 km) and is shallow by North Sea standards, lying just 1,650 metres below the seabed. To tap as wide an area as possible, the development plan involves two drilling centres, with 29 wells drilled around these centres. Horizontal and multilateral wells were used extensively. Some of Foinaven's wells had horizontal sections up to 1,000 metres in length to expose a large section of the reservoir to the well bore. The multilateral wells allowed up to three bore holes to be drilled from the same wellhead.

Each well needed to be connected back to its respective manifold centre, and the two manifold centres needed to be connected back to the FPSO. This development plan resulted in a large number of flowlines, pipes and umbilical connections on the seabed. The technology for making diverless connections was developed as part of the Diverless Maintained Cluster (DMaC) project (see *Petroleum Review*, June 1999).

The first underwater trial of the flowline pull-in system was carried out in Fort William in 1991. Further trials were performed on a test structure in the Foinaven field before the start of the actual installation work. Each pipe connection was made by pulling a flexible jumper into position by means of wire rope, with a winch on the ROV providing the power. Special docking features ensure that the components mate correctly, Retlock clamp couplings making the final fluid tight connection.

The final connections between the subsea systems and the FPSO were made by means of 14 flexible risers. The FPSO is held in position by 10 anchors. A turret gives the vessel a 'weathervane' capability allowing it to change its position in response to wind, current and sea conditions. To meet the tight schedule it was decided to convert an existing vessel, rather than construct a new FPSO.

Field partners BP and Shell issued a contract to a consortium formed between McDermott International and Golar-Nor Offshore for conversion of the Finnish-built vessel *Anadyr*. The contract involved completely rebuilding the vessel which has a crew of 45 during normal operations, with maximum accommodation for 75 persons. It is designed to handle 120,000 b/d of oil and has storage capacity of 280,000 barrels of oil in 15 tanks, together with gas lift and water injection facilities.

Although the subsea installation work appeared to proceed remarkably smoothly, the overall project was dogged by other problems and delays. One particularly annoying problem for BP was the discovery of leaks from subsea equipment. This equipment needed to be retrieved to the surface for repair before oil could be produced.

Lessons learnt

Lessons learned from Foinaven no doubt contributed to the successful development of the nearby Schiehallion and Loyal fields. These fields lie 15 km northeast of Foinaven and came onstream just 27 months after project sanction. The total recoverable reserves of these fields are approximately 425mn barrels.

The Schiehallion field was discovered in Autumn 1993 by the drilling rig Ocean Alliance. Following the discovery, 3D seismic was shot in 1993 and appraisal wells were drilled in 1994. A well drilled by Amerada Hess in an adjacent block proved that Schiehallion was an extensive reservoir and underlined its potential. The Loyal accumulation was discovered in late 1994.

An extended well test was carried out in 1995 and produced 700,000 barrels of oil with wells flowing at up to 20,000 b/d. BP says that this extended well test was crucial in providing the confidence to proceed with the project. The development plan gained government approval in April 1996 and represents an investment of around £900mn.

The plan involves a barge-shaped FPSO connected to 29 subsea wells, drilled around five well centres. The mooring system has 14 mooring lines connected to a turret near the bow of the FPSO. At 375 metres, the water was not as deep as Foinaven, though still too deep for commercial diving. Each christmas tree is connected to its manifold by means of the DMaC connection system pioneered on Foinaven.

The thin, almost flat-lying, reservoir formations will be drained by 16 horizontal production wells. The horizontal sections of the wells are up to 1,500 metres long. Twelve additional wells will inject water at the other points in the reservoir to sweep the hydrocarbons to the producing wells and maintain the reservoir pressure. One further well will dispose of gas and so avoid flaring. All wells were completed with screens to eliminate problems from produced sand.

The *Schiehallion* FPSO was officially named at the Harland and Wolff shipyard in Belfast on 5 December 1997 and was moved to the field early last year. It was the world's largest newbuild vessel at the time. The FPSO has processing facilities to handle 154,000 barrels of oil per day. Crude oil is stored in double-sided tanks and is exported by shuttle tanker moored to the stern.

The vessel has a simple, barge-type hull with high forecastle to provide protection to the forward process area and mooring turret. Despite these features, the vessel suffered some bow damage above the waterline during a severe storm in November 1998 and non-essential personnel were airlifted from the vessel to a nearby drilling rig.

Thrusters have been provided to ensure that the FPSO remains in a fixed position during shuttle loading operations. The recently completed tanker *Loch Rannoch* is on long-term charter for the shuttle transport role. The tanker is operated by BP Shipping and will visit every 4–6 days during peak production to transport oil to the Flotta terminal in the Orkney Islands. The tanker was constructed by Daewoo in South Korea.

A number of measures have been taken to reduce the environmental impact of this project. One measure was to inject associated gas back into a separate structure, instead of venting or flaring it. Volatile organic compound (VOC) emissions are reduced when transferring oil to the shuttle tanker through the use of a displaced gas recycling system.

Award-winning projects

BP's Foinaven and Schiehallion achievements were recognised when it received a Distinguished Achievement Award for Companies, Organisations and Institutions, at the Offshore Technology Conference, in Houston, Texas, in May this year.

Call to protect St Kilda

The United Nations' conservation advisors were recently reported to have called for the remote St Kilda islands in the Atlantic Frontier to be placed on its 'danger list' in order to protect the area's wildlife and environment from oil and gas exploration.

The islands were declared a World Heritage site in 1986. Environmental group Greenpeace is understood to have announced plans to send its *Rainbow Warrier* flagship to the islands this summer, in a bid to 'highlight the urgency of St Kilda's plight'.

Technology tackles challenging reserves

***Jeff Crook* takes a look at some of the more interesting project developments due onstream in the North Sea over the next year, including the implementation of some technological 'firsts'.**

The continued development of drilling and subsea technologies, coupled with the use of innovative approaches to project management, are facilitating the development of a number of North Sea fields that were previously considered economically unviable.

Unique pumps for Captain

Texaco's North Sea Captain expansion project is well underway with completion scheduled for 4Q2000. The project involves the installation of a subsea Area B drilling centre connected by pipelines to a bridge-linked process/utilities platform connected to the existing wellhead protection platform (WPP 'A'). It is said to be the world's first application of a unique downhole pumping system developed by Weir Pumps.

The Captain field lies approximately 130 km northeast of Aberdeen and has represented a major challenge for Texaco. Although it has estimated recoverable reserves of more than 350mn barrels of oil and 53bn cf of gas, it was considered uneconomic when discovered in 1977. It was only with the advent of modern technology, coupled with an innovative approach to project management, that the field became economically viable.

The reservoir covers a relatively large area (10 km by 4 km) and is being developed in two phases – the first of which completed in December 1996, the second currently underway. Captain's crude is heavy and viscous, so downhole pumping had to be provided to achieve economic production rates. Some Area B wells are also said to be gassy, a factor complicating the downhole pumping process.

Economic development of the field required the use of extended reach horizontal wells. This was made more complicated because the reservoir was shallow by North Sea standards, lying just 900 metres below the seabed. Some wells drilled for the first phase of the development had horizontal sections between 4,600 ft and 6,000 ft in length.

The Captain A development came onstream in March 1997 and involved an investment of £500mn. It consists of a floating production, storage and offloading (FPSO) vessel connected to a wellhead protector platform (WPP). Electrical submersible pumps (ESPs) were deployed in each of the wells – each ESP was designed to lift 20,000 b/d of fluid.

Texaco considered a range of options for development of Area B, the eastern part of the field. The final solution involves a new platform bridge-linked to the WPP, together with an 18-slot subsea manifold. The £350mn investment will result in an increase in the current production capacity of 60,000 b/d to 100,000 b/d.

Texaco explained that the new platform provides a more effective location for process equipment than modifying the FPSO. The tie-back from the subsea manifold to the platform is around 5 km in length. The newly developed hydraulic turbine driven submersible pumpsets (HSPs) will be installed in the wells drilled through the subsea manifold.

Field trials

Weir Pumps was awarded a contract worth approximately £7.5mn to supply 15 HSPs for the project following a successful trial in a producing well on the WPP. The new downhole pumping system was developed for handling elevated gas fractions. The R&D was supported by Texaco, the UK Department of Trade and Industry, the Offshore Supplies Office and Scottish Enterprise.

Commenting on the order, Graham Bibby, Sales and Marketing Director of Weir Pumps, said: 'The Captain reservoir requires downhole pumps to lift well fluids artificially to the surface and the HSP is considered ideal for this purpose. It is a highly reliable machine and should operate for several years in the high gas fractions found in the Captain Area B reservoir.'

Weir says that when the HSP undertook its offshore field trials it operated on elevated gas fractions ranging from 35% to 75% at pump suction in a slugging multiphase regime without gas locking. HSPs had already been tested at Texaco's Humble facility in Texas at higher gas fractions (the units are actually designed to handle gas fractions up to 90%).

An HSP incorporates a turbine drive system which uses fluid power fed from a surface or subsea mounted charge pump. The power fluid returns to the surface, comingled with the produced flow from the pump. The turbine automatically adjusts its speed to compensate for the varying product density with changing void fractions; power supply being nominally constant.

Abrasion resistant materials are used in the construction of the HSP to withstand the erosive actions of sand particles present in the well fluid. The units are of compact design – typical length being less than 20 ft, less than one-fifth the size of more conventional equipment.

Fabrication underway

Work on the detailed design of the Captain B platform has been completed by a fully integrated team at Kvaerner's Croydon office and fabrication is currently underway at Kvaerner's Methil yard in Scotland. The $165mn platform is designed to stand in 350 ft of water. Installation and commissioning are due to be completed in summer 2000.

The platform order was good news for the fabrication yards which were fighting hard for work last year. Kvaerner Oil and Gas's Executive Vice President, George Mowatt, said that the £100mn contract was won against stiff competition and claimed that it was 'the largest to be placed in the UKCS this year'.

In March 1999, Texaco placed a £37mn order for the subsea template. The template will be supplied by a joint venture between Brown & Root and Cooper Cameron (UK), complete with trees, wellhead and control systems. Sailaway from Barmac's Ardersier site is scheduled for the middle of next year.

In June 1999, Coflexip Stena Offshore secured a £20mn pipelay contract for Captain. The contract covers the design, procurement, installation, tie-ins and commissioning of the pipeline system between the bridge-linked process and utility platform and the subsea production facilities template. The workscope also included the supply and installation of two control umbilicals. The pipeline – manufactured at Coflexip's Evanton spoolbase in Scotland – will be installed by *CSO Apache*, a diving support vessel (DSV) and the *Normand Pioneer*.

Texaco (85%) and partner Korea Captain Company (15%) entered into a gas export and offshore fuel supply agreement in July 1999 with Total Oil Marine, operator of the Frigg UK gas transportation system and its co-owner Elf Exploration. The associated gas will be produced from Area B. Ultimately, the partners hope to export up to 18mn cf/d of gas from Captain.

Central Graben challenges

The summer months of 1999 have been a particularly busy period for those involved with the Shearwater, Elgin and Franklin developments in the central North Sea around 200 km due east of Aberdeen. First gas is expected from these gas condensate fields early 2000. With combined reserves of 700mn boe, the fields will help ensure secure gas supplies for the UK well into the new millennium.

Many reservoirs found in the Central Graben, a geological area straddling the UK boundary with Norway and Denmark, have deep high pressure/high temperature (HP/HT) conditions – Shearwater, Elgin and Franklin providing good examples.

It is only recently that North Sea operators have had the confidence to develop such fields – Texaco's Erskine field being the first North Sea HP/HT to come onstream in October 1997. The BP-operated Eastern Trough Area Project (ETAP), which came onstream in July 1998, also involves a number of HP/HT fields and lies in the same general area.


Captain A's wellhead protection platform

Coping with HP/HT

A HP/HT reservoir needs surface pressure control equipment rated for a working pressure of over 10,000 psi and has an undisturbed bottom-hole temperature of over 300°F. Such reservoirs are typically located at around 15,000 ft below the seabed and drilling requires careful planning and the strictest safety procedures. As a result, drilling is more costly and time consuming than for a more conventional field.

Wellhead components and production tubing are manufactured from high strength alloys with a greater wall thickness in order to cope with the enormous pressures at these depths. The stress analysis of such components is frequently checked by finite element analysis (FEA). Another feature of this highly rated equipment is that metal-to-metal joints are used, rather than conventional elastomer seals.

One of the key features of HP/HT developments is the need to drill all the development wells prior to the start of production. Currently, the technology is not economically available to drill into partially depleted HP/HT reservoirs. In the case of Shearwater and Elgin/Franklin, this has resulted in early installation of wellhead platforms as pre-drilling templates, which are then bridge-linked to processing facilities and living quarters platforms. The

The Shearwater development concept

resulting physical separation also enhances personnel safety by segregation from the HP/HT wells.

Cooperative pipeline project

Development of both the Shearwater field (operated by Shell Expro on behalf of Shell, Esso, Arco and Mobil) and the Elf-operated Elgin and Franklin fields got underway after the coventurers came to an agreement over a common gas export route to the mainland. There was insufficient spare capacity in existing gas pipelines – the Central Area Transmission System (CATS) is the main pipeline serving this region – so a new pipeline carrying sales quality gas is being built to link the offshore facilities to the Shell Expro-operated terminal at Bacton.

The Shearwater Elgin Area Line (SEAL) will have major strategic importance after the turn of the century because of the large gas reserves in the region. Elf is acting as operator of the pipeline during the construction phase, while Shell Expro will assume operatorship when the fields come into production. The pipeline is jointly owned by all coventurers in the related projects.

The 34-inch diameter gas pipeline has a total length of 463 km. McDermott-ETPM (UK) is laying the pipeline using the monohull laybarge *DLB1601* under a £200mn contract. A second 24-inch diameter pipeline is being laid to export liquids – this line will tie-in to the Forties pipeline system.

The Shearwater and Elgin/Franklin developments both have a main production platform bridge-linked to a smaller wellhead platform. Production wells are drilled in both developments by jack-up rigs cantilevered over the wellhead structures. The main difference between the two developments lies in the design of the main production platforms. A large integrated processing, utilities and quarters (PUQ) deck is being used for Shearwater, while a self-installing jack-up platform is being used for Elgin/Franklin. Both these solutions minimise the hook-up work to be done offshore. However, the self-installing platform avoids the requirement for a heavy lift vessel to install the deck and modules.

Shearwater development

The Shell-operated Shearwater development consists of a main production platform standing in 90 metres of water, bridge-linked to a wellhead platform which stands 80 metres away. The facilities have capacity for producing 410mn cf/d of gas and 90,000 b/d of condensate. Estimated recoverable reserves are around 850bn cf of gas and 159mn barrels of condensate and liquids.

A spokesman for Shell Expro said: 'The concept was determined under a design competition where four consortia made economic and technical proposals. Selection was based on the proposal which optimised project economics.'

Drilling started shortly after installation of the jacket for the wellhead platform in mid-1997. The early installation of this jacket meant that drilling operations could proceed while the main facilities were under construction. The wellhead jacket is being used as a template by the *Maersk Endurer* jack-up drilling rig. The 2,500-tonne, four-legged jacket was engineered and fabricated at Oderbrecht Oil and Gas in Teesside under a £20mn contract.

Shell Expro formed a well engineering alliance with Maersk Drilling for the five production wells. The *Maersk Endurer* underwent a refit in the US to equip it for the HP/HT drilling programme. The rig is operating in a cantilever arrangement in which the jack-up stands alongside the jacket, and the drilling derrick is moved outwards along beams projecting from the side of the jack-up's deck. In this way, the drilling derrick is supported above the jacket.

The Shearwater wells are being drilled to a depth of 16,000 ft (4,900 metres) below the seabed, and are reported to be significantly ahead of schedule and under budget. The third well was tested and flared towards the end of last year.

Once the wells have been drilled and completed the flowlines will be connected into a common production manifold on the wellhead platform and piped across the bridge to the primary separator on the main production platform. The installed weight of the PUQ topsides is 12,500 tonnes.

All processing will be carried out offshore to enable gas to enter the distribution system without any further treatment onshore. Separated condensate will be transported by the 24-inch pipeline, while provision has been made for a third hydrocarbon output stream should favourable commercial conditions arise.

The field's facilities are being developed by an alliance which Shell has formed with Amec and Heerema. A contract worth in excess of £350mn covering the design, procurement, construction, installation and hook-up of the central processing platform and the topsides for the wellhead jacket was awarded in early 1997.

Fabrication of the integrated deck is progressing at Amec's Wallsend yard on the Tyne. The wellhead topsides and main jacket were fabricated at Heerema's Hartlepool and Vlissingen yards. The 600-tonne incinerator, together with the flare and bridge, are being built at Heerema Hartlepool while Oderbrecht is constructing the cabins module at Lowestoft. The wellhead topsides and main PUQ jacket were installed offshore at the beginning of May 1999.

The large size of the deck means that most of the hook-up and commissioning work can be completed in the fabrication yard. However, the offshore lift will be a Herculean task – claimed to be one of the heaviest lifts ever undertaken in the North Sea. The Heerema heavy lift barge *Thialf* is due to perform the lift early next year.

Elgin/Franklin development

The Elf-operated Elgin/Franklin development involves two wellhead platforms connected to a main production platform. The Elgin wellhead platform will be bridge-linked to the main production platform, while the Franklin platform will be situated approximately 5.5 km away. Franklin will be a 'not normally manned' platform with an emergency accommodation/refuge and helideck. It is connected to the main production platform by infield lines for fluid export and services.

The wellhead jackets were fabricated at Lewis Offshore in Stornaway and were installed by Saipem using the vessel *S7000* in late summer 1997. Each jacket weighs around 3,000 tonnes and stands in 93 metres of water. A £50mn contract was placed for engineering procurement, fabrication, transportation and installation of the wellhead platform decks with Kvaerner Oil and Gas. Each deck weighs approximately 2,000 tonnes.

Santa Fe Drilling Company is carrying out the drilling operations with the Galaxy 1 jack-up drilling rig deployed in the Elgin field, and the Magellan in the Franklin field.

Elf and its coventurers selected a TPG500 heavy-duty jack-up platform for the main production platform. This concept should provide significant cost savings through the use of low cost construction techniques and the elimination of the majority of the offshore hook-up work. The overall structural weight at sailaway from the Nigg fabrication yard will be 35,000 tonnes.

The TPG500 concept is like a large jack-up drilling rig with process equipment, utilities and accommodation installed on the deck, but without any drilling equipment. The design enables all process hook-up and commissioning to be carried out in the construction yard before the unit is towed to its offshore site. The entire topside structure is raised by means of the jack-up legs and thus eliminates the need for an expensive heavy lift vessel to install the topside modules. This innovative approach was first used for the BP-operated Harding field in the North Sea. However, unlike the Harding platform, the Elgin PUQ does not have a concrete base.

The TPG500 is to be built by the TMB Consortium, which comprises TPG (UK), a subsidiary of the Technip Group, McDermott Marine Construction Ltd, and Brown & Root McDermott Fabricators (Barmac). The unit is being built at Barmac's yard in Nigg, Scotland. Technip-Geoproduction designed and engineered the structure, including jacking and locking systems for the legs.

Shearwater will use what is claimed to be the world's first 15,000 psi xmas tree. The tree was installed in April 1998.

Machar subsea challenge

The Machar subsea production system forms part of the multi-field HP/HT ETAP project, and is said to have the longest tie-back of any oil satellite in the North Sea. It is expected to contribute 30% of the oil revenue for the £1.6bn multi-field development and uses sophisticated subsea technology to reduce pipeline costs.

ETAP lies around 200 km east of Aberdeen and will eventually produce 210,000 b/d of oil and 360mn cf/d of gas. The main facilities came onstream in July 1998, with the subsea satellites coming into operation during the following months. The scheme required a high degree of cooperation because four fields were operated by BP and the remaining three by Shell Expro.

The field partners faced a variety of challenges including high temperature, high pressure reservoirs, technically complex wells and distant subsea satellite tie-backs. However, the water depths are reasonably modest at just 85 to 95 metres.

A central processing facility (CPF) was installed on Marnock field, an unmanned production platform on Mungo, subsea production manifolds on Monan and Machar, and subsea wells on the three Shell-operated Heron cluster fields. All the satellite facilities are tied back to the CPF from where oil is exported through the Forties Pipeline System to Cruden Bay, and gas through the Central Area Transmission System (CATS) to Teesside.

The Machar manifold lies 35 km from the CPF and is linked to it by a single production flowline. The use of new technology allowed the project team to eliminate a second 35-km flowline from the overall scheme, thus saving several million pounds in construction cost. A newly developed subsea pigging system, together with subsea multiphase meters, made this possible.

Innovative pig

The project team recognised from an early stage that the pipeline would need to be pigged at regular intervals because wax deposits were expected to occur as hot well products were cooled by seawater surrounding the subsea pipelines. The problem of pigging has long been regarded as a limitation to the use of subsea production systems because of the difficulty of inserting a pig into a high pressure pipeline on the seabed. The normal approach to this problem is called 'round trip' pigging in which pigs are inserted and retrieved from the surface. However, this approach requires a pair of pipelines to be provided and connected into a loop.

Instead of the round trip approach, BP decided to develop a subsea pig launcher for the project. This is thought to be the first subsea system for routine pigging operations in the North Sea. Having studied various options BP awarded a contract to GD Engineering of Worksop to design and manufacture the unit. GD Engineering says that it received 'invaluable' input from the alliance partners, BP, Brown & Root, and Coflexip Stena Offshore for the operational aspects of the project.

The Machar subsea pig launcher system has storage capacity for three pigs, and a pig release mechanism which can be operated by remote operated vehicle (ROV). The pig launcher assembly is pre-loaded with pigs on the shore and deployed from a diving support vessel or drilling vessel to the subsea manifold using guide wire alignment. Once the three pigs have been released the launcher is brought back to the surface for reloading.

Pigging operations began in September 1998 with the launch of three pigs from Machar to the central processing facility. The pigs are currently being launched on a three-month schedule.

Multiphase meters

As a further innovation, subsea multiphase meters were installed on the Monan and Machar subsea production manifolds to enable the performance of individual wells to be assessed close to the wellhead. The use of this technology was another factor enabling a single flowline to be installed from each subsea manifold to the CPF. A second flowline has been needed on other projects to transport the flow from a single well, separate from the main comingled production stream, so that testing can be carried out on the host facility.

The Machar satellite will also use subsea multiphase booster pumps in conjunction with water injection to maintain production as the reservoir pressure starts to decline. Reservoir pressure should be adequate to drive the production fluids from Machar to the CPF for the first year of operation.

Two subsea multiphase booster units were supplied by Framo Engineering for the project. The pumps are installed on a common structure on the seabed 30 metres downstream of the production manifold. A flow homogeniser has also been provided to smooth out the effects of slugging. The injection water will power the subsea multiphase pumps before the water is injected into the reservoir. This system is similar in concept to that adopted by Shell for the Draugen field.

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from a platform (as opposed to a subsea development) are well known. These include lower capital expenditure, reduced operating cost per barrel and easier well re-entry for maintenance purposes.

Future activity

Recent months have been fairly lean times in terms of down-manning of drilling crews and the associated offshore and onshore redundancy exercises across the industry. Activity may not quite return to its levels of early 1998 but the drives to apply new techniques and new technology are continuing and will undoubtedly assist the CRINE Network's ambition of reducing the recovery cost per barrel from the current estimate of $13. The UK's fleet of platforms is still the scene of innovative, progressive and exciting drilling techniques. With the recent oil price shock this will continue and the value generated will be even more beneficial as oil prices rise.

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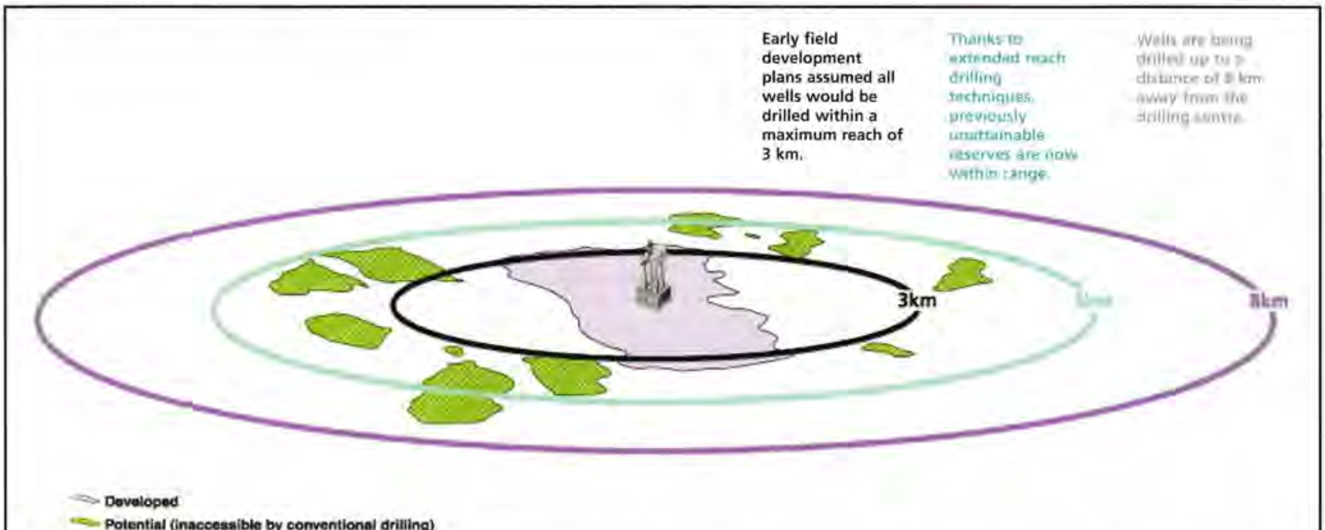

Figure 2: Extended reach wells target the extremities of the main field and earlier inaccessible accumulations beyond the main field

Norwegian prospects on the up

Field development activity in Norway is showing the first welcome signs of recovery after following the oil price into collapse last year, writes *Nick Terdre*. New projects such as BP Amoco's Tambar, Norsk Hydro's Tune and Saga Petroleum's Borg are moving ahead, signalling a readiness on the part of field licensees to ease spending controls.

The Norwegian offshore industry has been through a roller-coaster ride in recent years. A surge of developments headed by Statoil/Saga's Åsgard project took investments to record levels in 1997 and 1998, at which point the government imposed a 12-month moratorium on a dozen development projects as the volume of work threatened to overwhelm the sector's resources. The plummeting oil price produced a more drastic cooling-off effect, as upcoming projects were shelved across the board.

Since early this year there has been virtually no fresh project work out to tender. In recent months lay-offs have taken place at fabrication yards where work has begun to run out. However, the short-term outlook is now somewhat improved, with up to six platforms, most of them admittedly small, likely to be contracted next year. If oil prices maintain their recent strength, the number of new projects will probably increase. But a return to the golden age looks highly unlikely, and eventually a reduction in fabrication capacity looks inevitable.

Key infrastructure

The common theme uniting the Tambar, Tune and Borg projects is the use of existing infrastructure. Tambar is an oil field with some 50mn barrels which BP Amoco is planning to tie back to the Ula platform, where its associated gas will be used for reservoir injection in order to improve recovery by 20mn to 22mn barrels and extend field life. The operator is evaluating the reuse of 2/4-G, the redundant Valhall riser platform situated at the Ekofisk centre, which would be good news for the reuse lobby though not for fabricators. A NKr1.1bn development plan should be submitted in late 1999, opening the way to start-up in spring 2001.

Norsk Hydro applied for permission to develop the Tune field mid-year. Its NKr2.6bn plan calls for subsea wells on a four-slot template tied back to the Øseberg D gas platform, on which a tie-in module, and at a later stage a dehydration module, will be installed. The Norwegian gas supply committee (FU) has recommended exports of 17bn cm and start-up is scheduled for October 2002. Tune also contains an estimated 36.5mn barrels of condensate.

Borg is also a subsea development, in this case utilising the Tordis area infrastructure in Saga's 'home' block 34/7. Permanent production was approved in July and oil is already flowing from a well drilled on the Tordis East template which was used for a long-term production test last year. It will be supported by a water injection well connected to the main Tordis manifold. A second producer and injector are expected to be drilled at a later stage. The cost of developing Borg's 75mn barrels of reserves is estimated at a very reasonable NKr800mn.

A number of other projects are also being actively worked on. Esso is preparing to develop the neighbouring Forseti and Ringhorn satellite fields in block 25/8 which have oil reserves well in excess of 100mn barrels. Its base case plan is a drilling platform with first-stage separation capability tied back to the *Balder* production ship. A fabrication contract is expected to be let next spring, leading to first oil in early 2002. The project is believed to be costed at around NKr5bn.

Norsk Hydro is also working on a plan to unlock the 630mn barrels of heavy crude in the Grane field in block 25/11, just south of Balder. Having scrapped as uneconomic a previous scheme for a two-platform development using carbon dioxide injection into the reservoir, it invited bids in July for the basic engineering for an integrated drilling, production and accommodation platform with a 25,000-tonne topsides, making it the largest structure currently in prospect in the sector. Recovery will be assisted by the injection of imported gas. At the engineering stage Norsk Hydro wants to see the current cost estimate of NKr15bn reduced. It hopes to submit a PDO late this year and achieve start-up in 2003.

BP Amoco is also dusting off the on–off Valhall water injection project. This envisages a 19-slot injection platform which could raise recovery by 150mn barrels at a cost of just under NKr3bn. Fresh reservoir studies are being carried out with the aim of identifying further upside potential. The company, which says fiscal concessions are needed to make the project viable, aims to deliver a PDO before year-end. Start-up would seem likely in 2002.

Phillips is now evaluating Ebba, a high-temperature, high-pressure discovery made by exploration well 2/7-31 this summer. Liquids and gas were tested, but the operator has not revealed any reserves estimate. It did, however, say that the nearby presence of infrastructure was positive from a development point of view – Ebba lies 10 km west of the Embla wellhead platform and about 25 km south of Ekofisk.

Last year Norsk Hydro discarded separate developments for the Fram and Gjøa fields in quad 35 as uneconomic, but is now actively working on a coordinated plan for the so-called Sogn area embracing these fields and other finds in the area, where it calculates reserve potential at 540mn barrels of oil and 110bn cm of gas. Some of the gas potential could be proved up by the Aurora well spudded in July by BP Amoco in block 35/8, where two gas finds have already been made. Norsk Hydro is currently looking at deploying a floater with phased production starting in 2004.

Fields onstream

Field development investments this year are estimated at NKr35.6bn, down from last year's record NKr45.2bn. They would have fallen more sharply but for the large number of projects already in hand, most of them running over budget and behind schedule. Since last October Statoil's Gullfaks satellites oil phase and Åsgard oil, Saga's Tordis East and Varg, and Norsk Hydro's Visund and Øseberg East have come onstream. This year should also see start-up on Esso's Balder and Jotun fields, Norsk Hydro's Troll II oil and Øseberg gas, and Statoil's Statfjord Northern Flank and Yme Beta West.

These should be followed next year by Statoil's Åsgard gas field, Heidrun North Flank and Sygna and Norsk Hydro's Øseberg South, while the start-up of water injection on Phillips' Eldfisk field is also due. In 2001 Saga's Snorre North and Statoil's Huldra gas field and Gullfaks Satellites gas phase should come onstream. With these fresh resources Norway's oil production is forecast to rise to 3.5mn b/d in 2000 and peak at just over 3.7mn b/d in 2001–02.

Future development

In the longer term some sizeable finds in the Norwegian Sea are also candidates for development. BP Amoco is preparing to drill an appraisal well on its Skarv discovery in block 6507/5, where it estimates oil reserves at between 200mn and 500mn barrels. Development could be coordinated with that of Statoil's new C-Fangst find some 7 km distant in block 6507/3.

Following the takeover of Saga by Norsk Hydro and Statoil, the latter company will now become responsible for the Halten Bank South development, involving oil, gas and condensate reserves in the Kristin, Lavrans, Tyrihans and Trestakk fields. An agreement already exists to use the export facilities on nearby Åsgard, though like Saga, Statoil will doubtless be keen to reduce capital expenditure (capex) from the current level. Saga's target start-up date for the first field, Kristin, is 2004.

Looking ahead, Norsk Hydro and BP Amoco have the giant Ormen Lange/Barden gas field to bring onstream. This stretches over three mid-Norway blocks – 6305/4, 5 and 7 – and lies in waters between 850 metres and 900 metres deep, making it the deepest water depth prospect so far in Norway. Various concepts are under study, including subsea wells tied back to a fixed platform in shallow waters, and floaters such as a tension-leg platform and spar platform. An export pipeline linking into the North Sea pipeline network will also be required, giving an overall development and export cost currently estimated at NKr40bn. According to Norsk Hydro, earliest start-up will be in 2007.

Over the next few years additional gas reserves will have to be developed to meet export commitments. These are likely to include a number of fields in the Gullfaks area, such as Statoil's Kvitebjørn and Gullfaks Gamma fields, though the latter needs further appraisal. As the Frigg field nears the end of its producing life, Norsk Hydro plans to create a new gas link to the UK by connecting the Heimdal platform to the Frigg export system. The Vesterled pipeline should be in operation no later than autumn 2002.

Meanwhile, Statoil is actively investigating ways of developing the Snøhvit, Albatross and Askeladd fields in the Barents Sea – gas reserves in the so-called Tromsø Patch are estimated at 316bn cm. Subsea wells tied back directly to shore are the currently favoured concept. These reserves will be exported in the form of liquefied natural gas, with earliest start-up in 2005.

Danish developments

Denmark is going through an expansive period at the moment, with new developments including the Danish sector's first ever concrete gravity base structure.

In March Statoil brought the Siri field onstream, the first in the sector which is not operated by Maersk. Siri, which has plateau production of some 50,000 b/d and reserves of some 60mn barrels, is being produced through an innovative combination of a jackup platform with processing facilities linked to a wellhead tower, both structures supported on a steel storage tank on the seabed.

A second non-Maersk operated field, Amerada Hess's Arne South, came onstream in July. The field, which has reserves of 88mn barrels and 6bn cm of gas, has been developed with a concrete gravity base structure, the first in the Danish sector. Oil will be offshore loaded, and gas exported through a new pipeline to shore at Nybro. In July operator DONG was carrying out repairs to the pipeline's lay-down head, which was damaged prior to being tied in. There are two small satellite fields, Amalie and Bertel, in the Arne South region, but these are unlikely to be tied back for a few years as platform capacity will be fully occupied with production from Arne South itself.

Meanwhile, Maersk has a fast-track development on its hands in the shape of the Nana-1 find which was made only this spring. Mid-year the operator was prequalifying contractors for both platform fabrication and pipelay – it is presumed the field will be tied back to the Dan field centre. Reserves have not been revealed, but Maersk seems optimistic that they could be sufficient to warrant partial processing on the field, as there will be provision for installing such facilities on the wellhead platform it is planning, fabricators say. Predrilling is due to start this autumn, and start-up could take place in late 2000.

North Sea fields onstream in 1999 and beyond

Field name	Oil/gas	Block no.	Operator	Start-up	Oil reserves	Gas reserves	Prod. system	Peak prod. (yr)
UK								
Onstream 1999								
Banff Phase II	oil	29/2a, 22/27a	Conoco	Jan-99	60mn b	39bn cf	Ramform FPSO	60,000 b/d, 90mn cf/d
Bell	gas	49/23	BP Amoco	Jan-99		75bn cf	subsea to Bessemer	50mn cf/d (2000)
Bittern/G'mot W.	oil	Triton Project 29/1a,1b	Amerada Hess	Sep-99	110/35mn b	100/120bn cf	Triton FPSO	100,000 b/d
Brown	gas	49/30	Amoco	Jan-99		0.73bn cm	with Davy to Indefatigable	38mn cf/d
Buckland	oil/gas	9/18a (N)	Mobil	Oct-99	33mn b	33bn cf	subsea to Beryl	30,000b/d, 34mn cf/d
Corvette	gas	49/23, 24	Shell	Jun-99		200bn cf	wellhead platform	170mn cf/d (1999)
Dalton	gas	110/2b	Burlington Res	Oct-99		120bn cf	subsea to Morecambe	100mn cf/d (2000)
Egret	oil/gas	22/24d	Shell	Jan-99	16mn b	20bn cf	subsea to Marnock	20,000 b/d
Gannet G	oil/gas	22/21	Shell	Jun-99	15mn boe	5bn cf	subsea to Gannet A	8,000 b/d, 3mn cf/d
Janice	oil	30/17a	Kerr-McGee	Feb-99	70mn b		FPSO	50,000 b/d
Ketch	gas	44/28b	Shell	Oct-99	3mn b	390bn cf	wellhead platform	150 mn cf/d (2000)
Kyle	oil	29/2c	Ranger	4Q99	35mn b		subsea via Banff	22,000 b/d (2001)
Mercury	gas	47/9b	BG	Nov-99		85bn cf	subsea to Neptune	35mn cf/d (2000)
Millom	gas	113/26a, 27a (SW)	Burlington Res	Oct-99		210bn cf	platform to Morecambe	100mn cf/y (2002)
Neptune	gas	47/5a	BG	Nov-99		285bn cf	platform to Cleeton	120mn cf/d (2000)
Orion	oil/gas	30/18 (E)	Talisman	Oct-99	15mn b	50bn cf	subsea to Clyde	14,000 b/d, 40mn cf/d
Pierce	oil/gas	23/22a,27	Enterprise	Feb-99	100mn b	200bn cf	FPSO Berge Hugin	45,000 b/d, 100mn cf/d
Renee/Rubie	oil/gas	15/27, 28b	Phillips	Feb/May-99	18mn b	13/3bn cf	subsea to FPSO	22-26,000 b/d
Ross	oil/gas	13/28a,29a	Talisman	Apr-99	68mn b	25bn cf	Bleo Holm FPSO	40,000 b/d, 13mn cf/d
Vampire	gas	49/16	Conoco	Oct-99		90bn cf	wellhead platform	50mn cf/d (2000)
Viking Gn	gas	49/17(N)	Conoco	Jun-99		100bn cf	wellh'd platfrm to Viking B	35mn cf/d (2000)
2000 and after								
Blake	oil	13/24a, 24b, 29b	BG	2001	65mn b		subsea to Ross?	40,000 b/d (2002)
Callisto North	gas	49/22	Conoco	2000		25bn cf	subsea tieback	20mn cf/d (2000)
Captain B	oil	13/22a	Texaco	end-2000			platform+18 well temp	85,000 b/d (+20 kb/d)
Cook	oil/gas	21/20 A	Enterprise	2000	20mn b	10bn cf	subsea to Teal FPSO?	
Elgin/Franklin	cond	22/30b, 30c, 29/5b	Elf	2000	244/123mn b cond		PDQ + wellh'd platforms	889/821bn cf
Europa	gas	49/22	Conoco	2000		107bn cf	subsea tieback	55mn cf/d (2000)
Jade	oil/gas	30/2c	Phillips	4Q2001	25mn b	450bn cf	steel platform via Judy	15,000 b/d, 200mn cf/d
Penguin A	hvy oil	211/13	Shell	2002?	30mn b	33bn cf	subsea to Brent	
Shearwater	gas/cond	22/30b	Shell	mid-2000	160mn b	850bn cf	PDQ + wellh'd platforms	78,000 b/d, 350mn cf/d
Sinope	gas	49/22	Conoco	2000		64bn cf	subsea tieback	40mn cf/d (2000)
Skua	oil/gas	22/24b	Shell	Jun-2002	27mn b	20bn cf	subsea to Marnock	19,000 b/d, 15mn cf/d
Possible developments								
Appleton	gas/cond	30/11	BP Amoco					
Arbroath/Montrose	oil	22/17, 18	BP Amoco				poss comp platform	
Auk North	oil	30/16	Shell	2000?	25-30mn b		subsea to Auk	
Bedevere	gas	48/14	Mobil	2000?		150bn cf	wellhead platform	
Beta UK	gas	44/24a	TotalFina	2002		150bn cf	wellh'd platform to NL	70mn cf/d (2003)
Block 15/23	cond	15/23d	BG					
Block 16/26	oil	16/26a	Arco					
Braemar	oil/gas	16/3c	Marathon	2001	15mn b	120bn cf	subsea to Brae B	5,000 b/d, 40,000 mn cf/d
Bressay	hvy oil	3/28a	Chevron					
Brigitte	gas		BG					
Cavendish	gas	43/19a	BP Amoco	2000		100bn cf	subsea to Trent	52mn cf/d (2001)
Chestnut	oil	22/2	Premier		15-30mn b		FPSO?	
Clair	oil	206/7a,8,9a,12,13a	BP Amoco	2004	263mn b		PDQ platform	80,000 b/d (2005)
ECA Phase II	gas	47/3b, 3c, 4a, 4b	BG	2001, 03, 05		390bn cf	wellhead platform	155mn cf/d (2006)
Elm	oil	16/12a	Lasmo	2001	6mn b		ERD from Tiffany	5,000 b/d (2001)
Enoch	oil/gas	16/13a	Petrobras	2002	12mn b	16bn cf	subsea to Miller or Brae	10,000 b/d, 15mn cf/d
Forties Satellites	oil	21/15a, 15b	BP Amoco	2001	15mn b		subsea to Forties	10,000 b/d (2001)
Fyne/Dandy	oil	21/28a	Lasmo	2002?	39mn b		FPSO?	
Gadwall	oil/gas	21/19	Shell	2002	9mn b	7bn cf	subsea to Kittiwake	10,000 b/d, 7mn cf/d
Goldeneye	oil/gas	14/29a, 20/4b	Shell	2002	15mn b	600bn cf	platform	5,000 b/d, 200mn cf/d
Halley	oil/gas	30/12b	BP Amoco	2000	19mn b	20bn cf	ERD from Fulmar	15,000 b/d, 15mn cf/d
Harding expansion	oil	9/23b	BP Amoco					
Hoton	gas	48/6, 7b	BP Amoco	2001		190bn cf	wellh'd platform to W.Sole	75mn cf/d (2002)
Inde NE	gas	49/19	Shell	2001		45bn cf	subsea tieback	50mn cf/d (2002)
Jacquie	oil/gas	30/13	Phillips	2002	14mn b	90bn cf	subsea to Judy	10,000 b/d, 50mn cf/d
Josephine	oil/gas	30/13	Phillips	2003	13mn b	95bn cf	subsea to Judy	8,000 b/d, 50mn cf/d
Kate	oil/gas	22/23b, 28a	Phillips	2001	30mn b	20bn cf	re-use of Maureen?	20,000 b/d, 15mn cf/d
Keith	oil/gas	9/8a	BHP	2000	9mn b	12bn cf	subsea to Bruce	13,000 b/d, 10mn cf/d
Kestrel	oil/gas	211/21	Shell					
Lambda	gas	110/13b,14 (W)	BHP	2001		80bn cf	subsea to Hamilton	60mn cf/d (2002)
Maclure	oil/gas	9/19 Area N	BP Amoco	2001	20mn b	30bn cf	subsea to Harding	15,000 b/d, 20mn cf/d
Magnus NW	oil	211/7a, 12a	BP Amoco	2001	10mn b		subsea to Magnus	6,000 b/d (2002)
Mariner	hvy oil	9/11a	Texaco	2002?	100mn b		project on hold	
Merlin phase 2	oil/gas	211/23a	Shell				one-well tieback	
NUGGETS	gas	3/18c,19a,19b,20a,24a, 25a	TotalFina	2003		500bn cf	subsea	150mn cf/d (2004)
Orca	gas	44/24a, 29b, 30	TotalFina	2002		250bn cf	wellh'd platform tieback to NL	120mn cf/d (2003)
Otter (Wendy)	oil	210/15a	TotalFina	2001	35mn b		subsea to Magnus	20,000 b/d (2002)
Peik UK	oil/gas	9/15a	TotalFina	2002	20mn b	350bn cf	subsea to Beryl A	9,000 b/d, 110mn cf/d
Perth	oil	15/21b	Amerada Hess	2002	45mn b		subsea to Scott	20,000 b/d (2003)
Pilot	oil	21/27	TotalFina	2002?	77mn b			
Puffin	oil/gas	29/4a, 5a, 9a, 10	Shell	2004	40mn b	320bn cf	wellh'd platform to Shearwater	18,000 b/d, 150mn cf/d
R Block	oil	15/27	Phillips					
Skene	oil/gas	19/9	Mobil	2002	65mn b	540bn cf	platform tieback to Beryl	27,000 b/d, 170mn cf/d
Skiff	gas	48/20a	Shell	2001		330bn cf	subsea to Clipper	65mn cf/d (2003)

North Sea developments

Field name	Oil/gas	Block no.	Operator	Start-up	Oil reserves	Gas reserves	Prod. system	Peak prod. (yr)
Skye	oil	211/23a, 23c	Shell	2001	20mn b		subsea to Dunlin	11,000 b/d (2002)
Solan								
Thebe	gas	49/22	Conoco	2001		74bn cf	with ECA Phase II	35mn cf/d (2002)
Tornedo	oil	22/23b, 28a, 28c	Shell	2002	30mn b		re-use of Maureen?	20,000 b/d (2003)
Whittle & Wollaston	gas	42/28a, 28b	BP Amoco	2002		180bn cf	wellh'd platform to Cleeton	85mn cf/d (2003)
NETHERLANDS								
Onstream 1999								
D/15-FA	gas	D/12, D/15	NAM	1999		430bn cf	platform	90 mn cf/d (2000)
K/6-G	gas	K/6	Elf	1999		145bn cf	platform	
K/6-T	gas	K/6	Elf	1999		34bn cf	platform	
K/9-8	gas	K/9A	TCPL	1999		70bn cf	platform	
N/7	gas	Noord	NAM	1999		35bn cf	platform	
2000 and after								
Hanze	oil/gas	F/2A	Veba Oil	2000	35mn b	58bn cf	platform	38mn cf/d (2001)
K/1A	gas	J/3A, K/1A	Elf	2002		414bn cf	platform	83mn cf/d (2003)
K/4-B	gas	K/4A	Elf	2000		260bn cf	subsea	
K/6-A	gas	K/6	Elf	2000		30bn cf	platform	
L/13-FA	gas	L/13	NAM	2002		30bn cf	platform	
L/4-F	gas	L/4A	Elf	2000		37bn cf	platform	
L/4-1	gas	L/4A	Elf	2000		52bn cf	platform	
Possible developments								
A&B Quadrant shallow gas	gas	A/12A	NAM	2004			platform	
Beta	gas	D/15	NAM	2001		38bn cf	subsea	18mn cf/d (2002)
G/16A	gas	G/16A	NAM	2002		226bn cf	platform	55mn cf/d (2003)
K/15-FE	gas	K/15	NAM	2002		30bn cf	platform	
K/2B	gas	K/2B	NAM	2001		86bn cf	platform	17mn cf/d (2002)
K/2B-K/3A	gas	K/2B,K/3A	NAM	2001		260bn cf	platform	
K/3A	gas	K/3A	NAM	2001		174bn cf	platform	35mn cf/d (2002)
K/4-E	gas	K/4A	Elf	2000		150bn cf	platform	
L/7-G	gas	L/7	Elf	2000		30bn cf	platform	
K/7-FB	gas	K/7	NAM	2001		150bn cf	platform	
K/7-FE	gas	K/7	NAM	2001		100bn cf	platform	
K/8-FB	gas	K/8	NAM	2002		40bn cf	platform	
L/1A	gas	L/1A	Elf	2000		31bn cf	platform	16mn cf/d (2001)
L/2-FB	gas	L/2	NAM	2000		95bn cf	platform	
L/8-14	gas	L/8B	Wintershall	2001		50bn cf	subsea	
L/8-P4	gas	L/5C, L/8C	Wintershall	2001		125bn cf	platform	
L/9-6	gas	L/9A, L/9B	NAM	2000		160bn cf	platform	
L/9-7	gas	L/9A	NAM	2000		100bn cf	subsea	
M/7-5	gas	M/7	Clyde	2000		91bn cf	platform	45mn cf/d (2001)
Orca	gas	D/15, D/18A	NAM	2001		75bn cf	platform	40mn cf/d (2002)
Q/4-8	gas	Q/4	Clyde	2000		69bn cf	platform	34mn cf/d (2000)
NORWAY								
Onstream 1999								
Åsgard A	oil/gas	6506/11,12,6407/2,6507/11	Statoil	May-99	132.3mn cm; 24mn t NGLs		FPSO, subsea, semi	227,000 b/d
Balder	oil/gas	25/10, 11	Esso Norge	3Q99	27.2mn cm	0.8bn cm	FPSO	73-75,000 b/d
Borg (H Central)	oil	34/7	Norsk Hydro	Jul-99	10-15mn cm		subsea via Tordis	25,000 b/d
Fangst	oil	6507/3	Statoil	1999			floater	
Gullfaks South	oil/gas	34/10	Statoil	Apr-99	18mn cm (oil); 9.3 mn t NGLs;54bn cm		subsea templates	73,000 b/d
Gullveig (Delta)	oil	34/10	Statoil	Mar-99	2.1mn cm		subsea to Gullfaks A	6,000 b/d
Jotun (Elli/Tau)	oil	25/8, 25/7	Esso/Statoil	Oct-99	30.7mn cm	1.8bn cm	FSPO + wellhead plat	90-100,000 b/d
Øseberg East	oil	30/6	Norsk Hydro	May-99	23.5mn cm	1.4bn cm	steel platform via Øseberg	66-75,000 b/d
Rimfaks	oil	34/10	Statoil	Feb-99	18.9mn cm	6.5bn cm	subsea to Gullfaks A	58 or 140,000 b/d
Troll West (C)	oil		Norsk Hydro	Nov-99	1.2bn b	83bn cm		100,000 b/d
Visund	oil/gas	34/8, 38/7	Norsk Hydro	May-99	48.5mn cm	51-56bn cm	FPO via Gullfaks C	95-100,000 b/d
Yme Beta West	oil		Statoil	3Q1999	16mn b		subsea to Yme	
2000 and after								
Aasgard B	gas	65,066,507	Statoil	4Q2000	191bn cm	38mn cm/d		
Dagny	oil/gas	15/5-1, 5-2	Statoil	2006	0.3mn cm(cond)	5.9bn cm		
Forseti/Ringhorn	oil/gas	25/10	Esso	2002	16.4mn cm	0.7bn cm	platform to Balder	
Fram/Gjoa	oil/gas	35/11, 9	Norsk Hydro	2004	41.9 bn cm; 7.2 mn t		floater	
Freja	oil	2/12 (Nway); 5603/27,28 (Dmk)	Amerada Hess		2mn cm; 0.1mn t	0.3bn cm	NNM platform	
Glitne	oil/gas	15/5	Statoil	2003	8.7mn cm	0.4bn cm	via Sleipner	
Grane (Hermod)	oil	25/11	Norsk Hydro	2003	84.5mn cm	1.8bn cm	PDQ platform	
Heidrun North	oil	6507/7,8	Statoil	2002	4mn cm	0.5bn cm	subsea tieback to Heidrun	
Huldra	gas	30/2, 3	Statoil	Aug-2001	7.9mn cm	22.3bn cm	partial process'g platform	
Kappa	oil/gas	30/6, 9	Norsk Hydro	2001	3.5mn cm	5.5bn cm	to Øseberg?	
Kristin	gas	6406/2, 11	Statoil	2004	250mn b	58.6bn cm	semi or FPSO	
Kvitebjorn	oil/gas	34/11	Statoil	2004	21.1mn cm (cond) ; 51.2bn cm; 4.4mn t		min. facilities platform	
Lavrans	oil/gas	6406/2	Statoil	2006	23.1mn t NGLs	72.6bn cm	subsea to Kristin	
Ormen Lange	gas	6305/1, 2, 4, 5	Norsk Hydro	2007		390bn cm	subsea to platform in 250m?	
Øseberg (A-struct)	gas/cond	30/9	Norsk Hydro	2002		30-40bn cm	NNM	
Øseberg South	oil/gas	30/9, 12	Norsk Hydro	Aug-2000	53.5mn cm	11bn cm	platform	
Sigyn	oil/gas	16/7	Esso	2004	1.8mn cm	5bn cm	to Sleipner	
Skarv	oil	6507/5	BP Amoco		30-80mn cm	30bn cm	floater?	
Skirne	gas	25/5	Elf	2002	1mn cm (cond)	5.1bn cm	subsea to Heimdal	
Snoehvit+ others	oil/gas	7120/5,6,7121/4,5	Statoil	2006	11.9mn cm; 15.3mn (cond)	163bn cm; 6.9mn t	subsea to shore	
Snorre B	oil	36/4, 34/7	Norsk Hydro	Aug2001	40mn cm		subsea to Snorre TLP	
STUJ	oil	34/7	Statoil	Jun-00	23 mn cm	14mn b	subsea	6,000 b/d
Sygna	oil	33/9, 34/7	Statoil	Aug-00	9.6mn cm	0.6bn cm	subsea via Statfjord C	40,000 b/d
Tambar	oil	1/3BP	Amoco	2001	8mn cm		wellhead platform	
Tommeliten A	oil/gas	2/4	Statoil	2001	3.2mn cm	3.5bn cm; 0.3mn t	subsea	
Trym	gas	3/7, 8	Shell	2001	0.7mn cm (cond)	2.7bn cm	subsea tieback to Harald (DK)	
Tune	gas/cond	30/8, 5	Norsk Hydro	2002	5.8mn cm (cond)	35bn cm	subsea to Øseberg	

Protecting networks

***Jason Holloway* of data security specialist Data Fellows identifies the issues in dealing with the latest generation of computer viruses.**

Viruses have changed from being a potential threat to being a very real threat. Witness the 'Melissa' virus and the more recent, and far more malicious, ExploreZip 'worm' virus which has caused considerable disruption to major corporates, including Microsoft, Merrill Lynch, Intel and General Electric. What's more, with the rapid and continuing expansion in the number of intranets, extranets and the Internet, such viruses are likely to become more prevalent.

So, how can you ensure that your network is fully protected from viruses, worms, trojans and other potential calamities? Simple steps such as not opening attachments in e-mails can provide a measure of protection, but viruses such as ExploreZip have got around this and can infect machines on a network without the user's knowledge.

The following paragraphs summarise the key issues involved in protecting your network and outline what to look out for when choosing your anti-virus protection.

Centralising control

Ease of management and deployment of your anti-virus solution will have critical implications for both the cost of administration and security effectiveness. Remote offices pose an administrative problem as, in most instances, they are only connected via gateways or dial-up connections to a slave system. In order for an anti-virus solution to be effective, the anti-virus policies of the entire organisation must be propagated and distributed to remote offices as well as within the local network, as many companies have found to their cost.

The administrator must also ensure that users do not disable their workstation protection either accidentally, or in an attempt to increase their computer's operating speed. So, the solution needs to be a transparent product, operation of which is hidden, requires no user action and integrates all desktop, server and gateway products in one unified management architecture.

Allies and enemies

Traditionally, anti-virus solutions have been set apart from general network security and are handled by desktop administrators and helpdesk resources. As there is no standard protocol across the security, encryption and anti-virus fields, complete integration can only be achieved by a vendor who has expertise and product ranges in all these fields. Very few do, so make sure your solution comes from one who does.

Conventional virus scanning software relies on updated lists of virus signatures to detect virus code. This method is dependent on both the completeness of the virus signatures identified by the software manufacturer and the thoroughness of the IT manager in updating the engine. An unknown virus will be missed, so ensure your anti-virus solution is updated daily from a Web resource to take account of new viruses. Remember, these emerge at the rate of several per day.

Some anti-virus products employ mathematical methods of scanning, which look for typical traces of viruses. These methods are useful, but prone to creating false alarms – expect these from any solution. Don't fall into the trap of trying to save time and money by disabling virus protection on the desktop and opting for protection on the server only. Many viruses commonly originate from end-user diskettes and are transferred via network connections – so they are in danger of passing unnoticed unless the company monitors all points of entry: e-mail, diskette, wide-area links and so on.

Since the first macro, or document-centric, virus was discovered in July 1995, their numbers have increased exponentially which makes it increasingly difficult to protect the corporate environment. By choosing a solution that takes a 'certification' approach to macro control you can add a future-proof solution to your network by distributing centrally-stored, trusted macro information to every desktop. Known macro viruses such as 'smart templates' or commercial templates from third-party suppliers are checked. Checks are then made for locally known macros that have been created for general use within an organisation. If a macro virus is found, the user is alerted and corresponding action, predefined by the administrator, is taken.

Identifying the solution

If no single anti-virus engine can achieve a comprehensive level of security, using two or more on the same network can offer better protection and help identify false alarms. In practice however, this 'two heads are better than one' approach has proved time consuming, difficult to implement and expensive to administrate. Problems can arise when two different drivers try to access the same file at the same time, as they can easily crash or generate confusing reports.

There is, however, a method of using two scanners to protect your network. Data Fellows' CounterSign framework provides a method for plugging in any anti-virus detection utilities and technologies as an ongoing protection against virus threats. This method boosts the chances of detection before the infection becomes an epidemic, and in tests scores consistently higher detection rates than alternative techniques.

If you bear all these points in mind when choosing your anti-virus solution you will ensure that your business has minimum risk exposure to the potentially crippling effects of a full-scale network infection. ●

North Sea fields onstream in 1999 and beyond... ***continued from previous page***

Field name	Oil/gas	Block no.	Operator	Start-up	Oil reserves	Gas reserves	Prod. system	Peak prod. (yr)
Tyrihans N&S	oil/gas	6407/1	Statoil	2006	15.9mn cm; 5.6mn t NGLs	28.7bn cm	subsea to Kristin	
Vale	gas/cond	25/4	Norsk Hydro	2001	3.9mn cm	3.2bn cm	subsea to Heimdal	
Volve(see Glitne)	oil/gas	15/9	Statoil	2003	12.1mn cm	1.8bn cm	to Sleipner	
DENMARK								
Onstream 1999								
Siri	oil	5604/20b	Statoil	Mar-99	9.5mn cm		jack-up system	50,000 b/d
South Arne	oil	5604/29c,30b	Amerada Hess	Jul-99	14mn cm	6bn cm	concrete platform	40-50,000 b/d
2000 and after								
Adda	oil/gas	5504/8	Maersk	2001+	1mn cm	1bn cm	subsea to Tyra?	
Alma	gas	5505/13	Maersk	2003	6mn b	30bn cf	platform	4,000 b/d, 22mn cf/d
Amalie	gas/cond	5604/26a	Danop	2000	13mn b	92bn cf	platform	7,000 b/d, 42mn cf/d
Elly	gas	5504/6a	Maersk	2001+	0.8mn cm	3mn t NGLs	NNM platform	
Gert	oil	5603/27a	Maersk	1999	9mn b	7bn cf	platform	6,000 b/d, 5mn cf/d
Igor	oil/gas	5505/13	Maersk	2001+	0.8mn cm	2bn cm	NNM platform to Dan?	
Nana-1	oil	5505/13	Maersk	2001	31.8mn cm		process platform	

Sources: UK Government (Brown Book), Norwegian Petroleum Directorate (1997, 1998 annual reports), Wood Mackenzie, Petroleum Review

Looking to the future

Ian Ward retired last month after eight years of service as Director General of the Institute of Petroleum. *Petroleum Review* asked him to highlight some of the key developments during his time at the IP and questioned what the future holds for Ian, the IP and the oil and gas industry at large?

Ian Ward, former Director General, the Institute of Petroleum

Q Before coming to the IP, you were a long-serving senior BP executive. What do you feel was your major achievement while there, and what are your happiest memories?

A I had 27 happy years at BP – originally Shell-Mex and BP before the split into two companies in 1976 – working in five key areas. I started in the Retail side in 1964 and worked in virtually every side of the business, starting off as a retail representative and finally running the BP retail network. I moved to the Aviation side as the Aviation Operations Manager in 1980 and then went on to manage the Distribution Division in 1983. If we are talking about what gave me the greatest satisfaction during my time at BP, I suppose what stands out is the fact that during 1983–86 we reduced our distribution operation costs by £15mn, improved the efficiency of the business and created better working relationships with our staff, in particular with our industrial workforce. We introduced an enabling agreement, which allowed the company to run its business far more effectively than had hitherto been possible because of restrictive union agreements, etc. I then spent three years in Personnel. My last three years with BP were in Europe running the operations side of its European supply and distribution businesses. I had 14 jobs in my 27 years with BP and never got bored – there were always new challenges to face.

Q The IP has undergone many changes in the past eight years that you have acted as Director General. What do you consider to be its most important developments and greatest achievements during that time?

A First, I must emphasise that everything that has been achieved by the IP over the years has been the result of the great efforts of the staff and support of the stakeholders and volunteers who have given freely of their time. The IP has, indeed, undergone a number of changes in the past eight years. Perhaps I can best illustrate that by comparing the environment of 1991 with today's. We had 27 oil company members, 340 corporate members and 6,900 individual members. Subscriptions from the oil companies, corporate and individual members accounted for 55% of our total income, the remaining 45% being self-generated. We employed nice people, very genuine and very loyal, and we had numerous volunteers – particularly in the technical area. We produced between four and five Codes of Practice each year. Brent crude in October 1991 was $23/b. Compared with today, we lived in a pretty cosy world.

Eight years on we have the same number of oil company and corporate members, despite the recent spate of mergers. Our individual membership has grown significantly, reaching 8,485 at the end of 1998 – an achievement of which I am particularly proud when you bear in mind what has been happening over the past eight years, with many people leaving the industry completely. We now self-generate 55% of our income, subscriptions accounting for the remainder, and employ increasingly professional and commercially aware people. Our Codes of Practice, guidelines, standards and research publications are the visible manifestation of what we do on the technical side of the IP. We produced 19 last year and have already published nine this year.

Regrettably, we have fewer volunteers able to give up their time to help the Institute. This is not surprising when you consider that those remaining in employment often have to work twice as hard on bigger portfolios than perhaps their counterparts had eight years ago. This is coupled with the fact that many past volunteers have now retired and have not been replaced by their companies.

Brent crude got down to $10/b earlier this year and has now moved up to $19. The key question is can that stick or will we see something nearer $15/b or even lower?

The world in which we operate today

is a much harsher one than eight years ago and we can no longer rely on company funding. We have got to find new ways of sustaining our operations through continuing self help and improving our professionalism in everything we do.

It is very difficult to pinpoint particular IP achievements, as by doing so, others which are equally important inevitably get put aside. However, one significant move was the introduction of our Lifetime Learning programme. At a time when companies are less parternalistic than before and employees are expected to take more control over their development, I firmly believe that what we have to offer – ie the provision of information through a variety of channels aimed at improving people's knowledge and skills, and hence, employability – provides benefits for everyone. Training is just one aspect of Lifetime Learning and in 1999 we introduced a major extension to our portfolio of courses. We plan to increase this further next year. On the technical side, the recent formation of the Scientific and Technical Advisory Committee (STAC) has given our technological drive much greater focus and should have a big impact on the Institute in years to come.

Q The past year has been a difficult one for the global oil and gas industry, with depressed prices and substantial cutbacks. From your knowledge and experience, when do you expect the industry's fortunes to turn around?

A Over the years, many people have been quoted trying to prophesise what is going to happen in the oil and gas industry and, more often than not, they are proved to be completely wrong – I am not going to fall into that trap! However, what I would say is that over the next five years the industry is likely to be employing fewer people, both technical and non-technical, and there will be fewer oil companies as more mergers occur. I expect that there will be a continuing shakeout of contractors, manufacturers and suppliers – but those that are left will be much stronger. As far as the oil companies are concerned, I think that there will be a continuation of outsourcing of non-core activities.

These changes will also impact those supporting the industry – the trade associations, institutes and other bodies – not only in terms of volunteer support but also the funding provided. We at the IP will continue to try to avoid any duplication of effort and I envisage some degree of amalgamation between like-minded organisations with similar goals in mind. I also think that Europe will have an even greater role to play in the business than at present – not only in how industry conducts its business in general, but also in terms of a continuing increase in legislation, environmental issues, product specifications, etc.

Q Jeff Pym will be taking over as IP Director General in September. What particular talents do you think he will bring to the job and have you any personal advice for someone taking over an organisation such as the IP?

A The IP is very lucky to have someone of Jeff's calibre joining it. He has a broad background in the industry, which will be of great benefit to the IP. He has worked in research – not only in the chemicals area but also upstream; in supply and trading; and government affairs. He has worked in the gas sector, both in Europe and the Far East, and most recently was President of BP Portugal. Apart from his great breadth of knowledge of the industry, I think his gas expertise in particular will be important to the IP as this is a sector which is of particular significance to the industry and which will be the growth area in the years to come.

Far be it from me to give advice to anyone but I think the most important thing is that Jeff be his own man and run the IP in the best way he sees fit. He has a solid base from which to start – the IP is financially sound and vibrant – and will have the full support of Council and the Management Committee. One thing for certain is that there will be numerous opportunities to grow the IP. The key will be to focus on those areas of particular importance and not try to spread the icing too thin on the cake by attempting to do everything at once.

Q Without tying your successor's hands or making comments on his behalf, how do you see the IP developing over the next few years to meet both the needs of its members and the industry at large?

A I believe the IP will continue to build on its strengths and expect it to go for growth in an even more positive way than it has done so in the past. Without being too specific and tying Jeff's hands, I can visualise lots of opportunities on the technical side. There is no shortage of projects for managing research studies or developing codes, guidelines and standards. STAC will have a major role in identifying and prioritising the programme. I am sure we will find new ways of supplementing the funding of some of this work which will help spread the burden of costs.

On the Membership Services side, the growth of conferences, training and other events will increase significantly. We've also achieved a high level of respectability in the publishing field and I am sure that we will continue to exploit new opportunities which will allow us to widen the scope of our publications, including *Petroleum Review*, and generate additional income which can be used to improve the services offered to members.

We have just refurbished our Library and Information Services department in order to meet the requirements of the 21st century. Our aim is to offer more information electronically and to provide it to remote locations rather than expect the user of the service to visit our premises all the time. The development of our web site, which has already achieved wide aclaim and a European award, will be ongoing.

There will be opportunities to increase our membership too, not only in the traditional generic growth way but also through step changes such as amalgamation with like-minded organisations both in the UK and Europe. In Education I believe there will be an even greater demand for us to supply material to aid teachers in covering the subject of oil and gas in the national curriculum as well as advice in career opportunities for students – as oil companies cut back on the level of material they currently provide.

Q I am sure that you have many happy memories of your time at the IP. Is there a particular favourite?

A I have eight years of wonderful, happy memories at the IP and to highlight particular ones is not easy. However, I suppose that two annual events stick in my mind, apart from IP Week and other business related activities. The first is the annual Pensioners Lunch at Christmas. This provides a unique opportunity for me to tell our retired staff how well the Institute has done during the year; it keeps them involved and emphasises that they have not been 'forgotten'. The annual Musical Evening is another key event for me. It provides the opportunity to thank in a small way all our supporters for the work that they have done, and will hopefully continue to do, for the Institute.

Q What are your immediate plans for the future?

A I have not finalised my plans. One thing for certain is that I will no longer be working five days a week – otherwise I would have stayed at the Institute. I intend to play more golf and I will have more time to spend in the garden and around the house – but I guess there will be a couple of days each week for doing something, either gainfully employed or working in the voluntary sector. I do not plan to vegetate! I will also look forward to hearing about all the new IP successes.

Offshore facility re-use – a viable option

The oil industry has been using offshore platforms as a means to exploit subsea oil and gas reservoirs for several decades. On depletion of the reservoir the production facility is no longer required and needs to be removed from its offshore location. Most, if not all, field operating agreements call for the operating company to make an effort to maximise the recovery of the assets. Likewise the licensing/governmental bodies require operators to carry out a thorough investigation into all options for the re-use or recycling of the oil and gas facility after field life. Re-use is a viable option and can lead to significant cost savings on new projects, writes *Otto van Voorst* of WEB Platform Brokers.

After the decision to remove a facility has been taken, several options are available to deal with the facilities:

- disassemble and sell as scrap;
- disassemble and sell reusable components, selling the remainder as scrap;
- re-use as a facility with another purpose (for example as a training centre or structures required near shore); or
- re-use as a production facility on another offshore reservoir.

It should be noted that the dumping and leaving of a facility, either wholly or partly in place, at sea is no longer allowed under the OSPAR (Oslo Paris Commission) convention. Derogations can be made if an assessment shows significant reasons why an alternative disposal option is preferable. For example, a permit may be issued for:

- all or part of the footings of a steel installation, weighing more than 10,000 tonnes in air, to be left in place, where the footings refer to the bottom bay of a jacket structure to which pile sleeves are attached;
- any other disused offshore installation to be dumped or left wholly or partly in place, when exceptional and unforeseen circumstances resulting from structural damage or deterioration can be demonstrated; or
- a concrete gravity based structure to be dumped or left wholly, or partly, in place.

Such derogations are not expected to be easy to obtain.

To date the practice in the North Sea has been the disassembling and selling of the majority of the facility as scrap. Some components, such as cranes, power-plant etc, have been re-used. Offshore production facilities, well maintained with a considerable residual life (for example Esmond and Odin) have, for the largest part, been recycled via the steel mill instead of being re-used as a complete facility.

On the Dutch Continental Shelf some operators – including Unocal, Wintershall and TransCanada – have re-used their own platforms to develop a new field nearby. Clyde is currently refurbishing a platform recently purchased from Wintershall. The operators claim significant capital expenditure savings as utilising refurbished existing facilities allows new fields to come onstream much earlier than is possible if a newbuild facility is required.

A serious alternative

When a facility nears the end of its field life the operator usually only seriously looks at decommissioning and scrapping options, not at total re-use. The marketing of the total facility for re-use should commence several years before shut-in date and the operator may not be aware of a market place where a potential buyer can readily be found.

Production facility re-use is a serious, cost-effective and time-efficient alternative to consider when developing a new field. However, the operator of a new field is usually not aware of existing facilities which could be available in time and which could be suitable for the new development.

Plans for new field development begin almost as soon as the first hole has struck hydrocarbons, facilities engineers assessing various field development scenarios while appraisal drilling continues to determine the extent of the find. As soon as further drilling is successful, a final development scenario is chosen and the project commences. At this stage, usually still some two to five years before first oil, the decision whether to consider re-using existing facilities should be taken. The time and capex savings provided through re-use should be quantified – but this can only be done if it is known which facilities will be available for re-use in time to improve the schedule, and if these facilities can be made compatible with the new field requirements.

Current information on platforms available for sale/re-use is not structured, is very limited and is based on a platform for platform basis. In addition, the information about the facility and its components is fragmented and not always completely relevant to a potential buyer.

The volume and presentation of information must be structured in such a fashion that a potential buyer can use it in order to be able to make a genuine comparison between re-using and refurbishing an existing facility (or its components) or building new. Furthermore the timing of making the information available must also suit the potential buyer. These issues can be organised using a computer-based database with a matching algorithm, resulting in easy access to full data on platforms that could be considered as suitable for use on the new field. However, such a scenario can only work effectively if all or most platforms available for re-use are loaded onto one database. This could be achieved by a joint approach from the operators – an approach which could also offer benefits for many other decommissioning issues.

The drivers for an operator developing a new field are totally different from the drivers in the decommissioning phase. First, the time element is no longer so important in the decommissioning phase, and, second, the operator's preferred specifications are not applicable. Confidentiality is also a much less important issue during the decommissioning phase.

Competition or one-stop-shop?

Engineers have devised a number of alternative methods to remove existing North Sea installations – usually requiring new vessels capable of removing the large structures. Such vessels require large investments. If two or three were to be built, competition would allow companies to effectively contract for the removal service. However, the vessels would still have to be built and paid for, and they would be depreciated over the contracts won. In the £20bn predicted decommissioning market this may well be justified – but what if the operators join forces, establish one team responsible for all removals in the North Sea and build only one removal vessel? The savings could be enormous!

If this joint operators team were to take on the responsibility not only for removal, but also re-use and dismantling, further significant savings are possible – not only financial, but also from an energy and environmental perspective.

Finger on the pulse

To enhance the possibilities of re-using a production facility at a new location the industry needs a 'market place' where the information on available facilities is easily accessible to facilities engineers developing plans for new fields. This market place needs to be managed by an independent organisation which has no relationships with parties interested in engineering, decommissioning or refurbishing activities. The market should be accessible to any serious party worldwide and should be quick in response. The Internet facilitates such access, although suitable security measures should be available to prevent the access to data by non-authorised users.

WEB Platform Brokers* is one such independent company, established specifically to make available to operators information on the offshore production facilities market place. The company operates an exclusive, sophisticated database programme, accessible via the Internet, which is capable of matching new field data with existing platform capabilities.

Several hurdles need to be overcome before re-use will be accepted as a realistic alternative to the decommissioning and scrapping of facilities:

Hazardous wastes – Every facility contains various hazardous wastes, either utilised in the construction phase (asbestos, PCBs) or as residues in the production phase (LSA, mercury). The national legislation applicable to hazardous wastes differs from country to county, but normally does not allow the export of certain hazardous wastes. To overcome this issue when re-using the facility in another country, the relevant hazardous wastes must be fully removed and properly disposed of in the country of origin. This will have to be done regardless of whether the platform is being re-used, recycled or scrapped. The new owner will thus only have to replace the items removed as hazardous waste (for example, living quarter sheeting or LSA-infected piping). Recent experience has shown that the extent of replacement is relatively minor.

Frame of mind – The oil and gas industry has always built new facilities utilising the latest technology, even though the basic process of oil, gas and water separation has not changed. To accept an existing facility as adequate for developing a new field will therefore require a change in the mind set of the engineers involved.

Fiscal – The operators have made substantial financial reservations for the removal and decommissioning of offshore production facilities. If the removal costs appear to be significantly lower once the first 10 or 15 major platforms have been removed from the North Sea, the reservations made may prove to be too high and the amounts reserved will be need to be adjusted.

Looking ahead

The re-use of high-spec North Sea facilities is a serious alternative to decommissioning and scrapping, offering significant energy, environmental and financial benefits. However, in order to be successful, management needs to be committed to considering re-use as an alternative to new building for every new field to be developed – the hurdles to be overcome are more psychological than physical.

If the operators join forces to create a single removal and decommissioning team, the potential of re-use is enhanced and budget savings could be enormous. ●

The company's website can be found at* **www.Web-Platform-Brokers.com

A conference on 'The Re-use of Offshore Production Facilities' is to be held in Den Helder, The Netherlands, on 13–14 October. It is organised by the Association of Technology Transfer North Holland (ATO-NH) in conjunction with the Institute of Petroleum, the IP Netherlands Branch, Aberdeen University Oil & Gas Institute and the Institute of Marine Engineers. For further information, contact: Pauline Ashby IP Conference Administrator, Tel: +44 (0)171 467 7100 Fax: +44 (0)171 255 1472 e: ***pashby@petroleum.co.uk***

Bulk Storage Survey 1999

We have a late admission to add to the listing in the Bulk Storage Survey published in last month's *Petroleum Review.*

Delta Petroleum Products Trading Co.

Delta Plaza Kastel Is Merkezi, Piyalepasa, Bulvari, Istanbul 80370, Turkey
Contact: Kelvin W Aldus
Tel: +90 212 2545414 (30 lines) +90 212 2536225 (10 lines)
Fax: +90 212 2534966/2534934
e: kaldus@deltapetrol.com
Facility address: Dortyol, Iskenderun, Turkey
Tel: +90 326 7341620 Fax: +90 326 7341628

- No of tanks: 19; Heated: 10
- Total storage capacity: 300,000 cm
- Minimum capacity: 12,500 cm
- Maximum capacity: 20,000 cm
- Range of products: Crude, oil products, chemicals
- Access: Road, Sea
- Largest vessel: 55,000 dwt
- Draft:16.25 metres

The terminal is strategically located close to the end of the Iraqi/Ceyhan pipeline and in a prime position to receive imports to Turkey and exports overland. The tanks can hold in excess of 2mn barrels of low- and high-flashpoint products such as crude, naphtha, gasoil, jet fuel and gasolines. The facility has integral heating and blending facilities. The road tanker discharge stations can handle 64 tankers and five different products simultaneously, whereas our triple buoy mooring system can accommodate two vessels up to 55,000 dwt and one vessel of up to 4,000 dwt.

May we also apologise to Robbie Reed of Ross Chemical & Storage Co Ltd for misprinting his e-mail address. The correct version is e: **rrr@kpgb.q8.co.uk**

The TC 67 suite continues to grow

As reported in the last two issues of *Petroleum Review*, many ISO/TC 67 standards are now being processed by ISO Central Secretariat for publication. These include a wide range of topics covering 'Materials, Equipment and Offshore Structures for the Petroleum and Natural Gas Industries'. Six standards have been published this year, the details of which can be found on our website at **www.petroleum.co.uk/tech/stds**

The following details of BS EN ISO 10441 and BS ISO 14224 have been provided by the leading technical experts who ensured that the UK oil industry was adequately represented during the development of the standards.

BS EN ISO 10441 *Petroleum and natural gas industries – Flexible couplings for mechanical power transmission – Special purpose applications*

An effective technical standard was required to ensure commercial pressures in the market place do not result in a coupling being supplied which may fail in service. This would have potentially disastrous results, both in terms of safety and economics.

ISO 10441 has been derived from API Standard 671 'Special Purpose Couplings for Petroleum, Chemical and Gas Industry Services'. Whilst most of the requirements of these two documents are the same, there are several significant differences, which make ISO 10441 an improvement on API 671. These are:

- **Coupling rating** – API 671 requires the coupling torque capability to exceed the service torque by a standard factor (service factor). The SF is required to be 1.75 for gear couplings and 1.5 for flexible element couplings. This SF is intended to allow for cyclic variations in the torque and also to allow for uncertainties in the service conditions and for possible future uprating. The level of possible cyclic variations is very different for different types of machine. The Working Group responsible for ISO 10441 therefore considered it more appropriate to use two separate factors. An application factor to allow for cyclic variations, which is dependent on the particular application and may be estimated or in some cases calculated; and an experience factor to cover uncertainties and possible future changes.

- **Balancing** – The mechanical balance of a typical coupling in service is very dependent on the accuracy and repeatability with which the various components can be assembled and mounted. Also, to balance an assembled coupling in the manufacturer's works generally requires the coupling to be 'locked-up' in order to mount it in the balancing machine. The repeatability of this locking-up process is such that an assembly balance cannot guarantee an acceptable level of balance in service. For these reasons the balance acceptance level of ISO 10441 is based primarily on the concept of 'potential unbalance'. Potential unbalance is the probable maximum unbalance resulting from the statistical summation of all the contributory causes of unbalance. In contrast API 671 permits a coupling to be assembly balanced.

- **Factor of safety** – API 671 requires a certain minimum value for the fatigue factor of safety based on published fatigue strength data for the materials used. For many types of couplings, the peak stress levels are very difficult, if not impossible, to calculate with any degree of precision. The ISO WG therefore concluded that to specify a minimum theoretical safety factor is meaningless unless the precise method of calculating the maximum stress is also specified, and that is only possible for very few types of flexible coupling.

The use of this standard is recommended for all machines in 'special purpose' applications. These are considered to be large or high speed machines in services that may be required to operate continuously for extended periods, are often unspared and are critical to the continued operation of the installation.

Peter Simmons,
Consultant, ISO WG Convenor & Project Leader

BS ISO 14224 *Petroleum and natural gas industries – Collection of reliability and maintenance data for equipment*

Sources of reliability data in the oil and gas industry vary significantly from the down hole safety valve on a subsea completion to the product loading pump in a refinery. Rather than give a prescriptive list of codes, ISO 14224 provides a standardized structure for data collection, which will enable data to be shared across the industry. This coding has been incorporated into several computerised maintenance management systems. Standardized coding brings many benefits, one of which is feedback of field data to equipment manufacturers. Increased knowledge of this kind is an opportunity for greater product reliability, bringing not only a competitive advantage to the vendor but also offering the potential for steadier plant operation, thereby improving safety and reducing losses for the operator.

Data has long been required for Reliability, Availability and Maintainability (RAM) analysis and for assessing the acceptability of High Integrity Protective Systems as part of Quantified Risk Assessments. Offshore Reliability Data (OREDA), the basis for the standard, has been used in many such studies, often for applications far removed from the offshore environment. A further advantage of the increased application of ISO 14224 will therefore be more data available, on a wider range of equipment and from differing environments. Hence there is the potential for more accurate reliability predictions in RAM analysis, the impact of which is the lowering of both capital and maintenance costs. Such data may be incorporated at any stage from project concept through to detailed design. Indeed, the use of OREDA data has already resulted in substantial savings on many projects in offshore exploration and production.

Data collection projects complying with ISO 14224 are being run in Norway (Sintef) for offshore applications and the US (Center for Chemical Process Safety and Solomon) for the chemical and refining sectors. Other applications for reliability data include Benchmarking Studies, Life Cycle Cost Analysis and Reliability Centred Maintenance.

David Thompson, Consultant, Lead UK Expert

If you would like to find out more about the other standards nearing completion on the TC 67 Work Programme, please contact either Sjoerd Schuyleman (Tel: +44 (0)171 467 7132, e: sfs@petroleum.co.uk**), or Martin Hunnybun (Tel: +44 (0)171 467 7133, e:**mh@petroleum.co.uk**).**

Our website can be found @ www.petroleum.co.uk

NEWS Technology

New sand control system cuts well costs

Aberdeen-based Petroline Wellsystems has continued its development of what is said to be the world's first expandable sand screen system (EES®) with its latest commercial deployment in the Netherlands.

The EES system comprises a sand exclusion screen that is capable of considerable expansion when a cone-shaped mandrel is driven through it. As the sand screen expands, it fits tightly into the wellbore, supporting the sand and reducing the likelihood of screen erosion and screen plugging due to particle migration. Once installed, the sand screen system allows control of hydrocarbon flow from the reservoir. It also enables selective remedial treatments such as acid stimulation – according to Petroline, EES is the only sand control system to currently offer this feature.

A 72mm length of the sand screen system was installed by Nederlande Aardolie Maatschappij in an offshore well in northern Holland and expanded from 4 inches in diameter to 5⅞ inches, in a gas reservoir at a depth of over 4,710 metres. The operation took only one hour to complete, a fraction of the time taken to install an equivalent gravel pack system, states Petroline.

According to Technical Director, Paul Metcalfe: 'This was the most technically challenging remit yet and EES was the only sand control technology on the market capable of meeting the requirements of the project. This latest success demonstrates that this new technology is no longer experimental – it has proven capabilities and can stand up to the toughest of tests.'

The EES technology is also claimed to have the capability to significantly reduce total well costs. Once installed, it can provide the same well diameter as a conventional sand control system, but requires a much slimmer well design. This can lead to well cost savings of up to 30% says Petroline. The company also states that when used in remedial sand control applications, the system can 'achieve work-over cost savings of millions of pounds per well'. It also estimates that EES could lead to increases in recovery of up to 10% during field life.

Tel: +44 (0)1224 423423
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Repower finance offer

Caterpillar Inc is offering a financing package for repower purchases of engines used in petroleum drilling and workover applications in North America. 'New orders must be received by 15 October 1999 for customers to realise cost savings,' states the company.

In addition, Caterpillar is offering deferred payment and decelerated payment structures or below-market interest rate financing tailored to contractors' needs. Certain trade-ins, down payments or credit approvals are required.

The company estimates that upgrading engines could save $10,000–$20,000 in fuel, making repowering less expensive than running an older engine.

Tel: +1 309 578 4710

Multitude of multi-parameter air monitoring devices

Zellweger Analytics has unveiled four new additions to its range of Solomat portable air quality measurement tools.

The new Solomat MP Surveyor II is designed to offer fast, simple and convenient multi-parameter air measurements. The unit's 'compatibility with Solomat Smart Probes means that no sensor programming is required and ensures that only the minimum of product training is required', states the company.

MP Surveyor II's self-recognition, four-function NDIR Smart Probe allows the measurement of up to eight parameters – temperature, humidity, carbon monoxide, pressure differential, airspeed, particulates and RPM. All information can be displayed simultaneously on the unit's large dot matrix screen.

The addition of Windows-based software allows the user to compile comprehensive logging ('snapshot' or continuous) information. This data can be exported to a spreadsheet program for storage and subsequent analysis.

The MP Surveyor Pro features a built-in micromanometer, a thermocouple and two additional sockets to allow simultaneous connection to Solomat Smart Probes. These features allow the user to establish the existence of pollution pathways within a building/structure and provide a proactive indoor air quality (IAQ) capability.

Solomat MP Survey II

The Solomat Zephyr II micromanometer is also portable and measures pressure, velocity, volume flow, % humidity, temperature, RPM and airspeed. It features a new, larger screen that can display up to eight air parameters simultaneously. A menu-driven display format provides step-by-step user guidance for each of the unit's operational functions, allowing the device to be used with minimal training.

Velocity and volume flow rate measurements can be automatically temperature compensated via the unit's thermocouple probe. A barometric correction can be entered manually. Zero-drift problems are said to be minimised through the use of an automatic balancing valve and electronic re-zeroing. Measurements can be presented in a wide choice of units, including SI, metric and imperial for pressure, velocity and volume flow.

The new Zephyr II+ has the same multifunctional features as the Zephyr II, but also includes snapshot or continuous data-logging facilities via Windows-based software.

Tel: +44 (0)1202 676161
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New pressure valves bring relief to operations

Anderson Greenwood recently launched an ultra-slimline Monoflange primary isolation ball valve for instrumentation pressure tapping duties. The unit is claimed to be particularly suited to applications where space and weight savings are crucial considerations.

The Monoflange features an integral forged body with a single 'super finished' quarter turn ball valve to reduce operating torque and wear. The ball is vented for upstream cavity relief and to provide uni-directional capability. A choice of soft seats are available, including PTFE and Devlon V. The unit also features a one-piece stem spindle for anti-blowout protection.

Monoflange primary isolation ball valve

To minimise overall profile, the ball valve is designed to be directly bolted to the vessel, process pipe or orifice carrier. Supplied as standard with a flanged inlet and threaded NPT outlet, the unit enables direct mounting of the pressure measurement instrumentation, or remote mounting using impulse tubing.

The valve can also be supplied with a flanged inlet and outlet to facilitate the mounting of flanged instruments, or blind flanged for use in venting and drain service. For added security, optional integral stud mounting bolts prevent disassembly of the valve body inlet from the vessel when removing the flanged instrument on the outlet connection.

A range of options, including a 360° rotatable gauge adapter and syphon, are available to tailor the unit to suit specific applications such as steam service.

The company has also launched the JOS-E/JBE-E generation of spring operated pressure relief valves for the overpressure protection of air, gas, steam, vapour, liquid and two-phase services in the power and process industries. The valves incorporate a number of design features developed to improve performance, reduce maintenance and ensure greater parts interchangeability, including a high guiding surface ratio, corrosion resistant trims and upgraded materials of construction.

The units feature an Inconel retention clip to firmly secure the disc insert into the disc holder. This two-piece design not only provides thermal balancing for maximum seat tightness but also enables the disc insert to be quickly removed for routine maintenance, states the manufacturer.

The disc holder design combined with threaded bellows and flange is also said to enable the valve to be cost-effectively converted from a conventional design to a balanced bellows design.

The JOS-E/JBE-E range of pressure relief valves is available with inlet flange ratings of ANSI 150, 300, 600, 900, 1,500 and 2,500. It is designed to withstand temperatures from –268°C to 538°C and pressures from 1.03 barg to 413.79 barg.

Tel: +44 (0)1858 467281
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Subsea pipeline protection

Hyperblast is to launch a new pipeline insulation and protection material – DW-512 – that it claims 'will take polyurethanes beyond existing limits for deepwater applications'.

The new material is a modified version of the company's 'Syntactic 512' syntactic elastomer which is designed to maintain product temperature over long distances in order to prevent hydrate formation in gases and waxing in crude oil subsea flowlines, manifolds and risers. Syntactic is a stand-alone, single layer coating whose closed cellular composition, based on the use of evenly distributed microspheres, provides physical protection and thermal insulation.

DW-512 also uses glass microspheres in its composition which allow it to be non-compressible at depths of more than 2,000 metres. Its insulation properties do not succumb to fluctuation, states the manufacturer.

There is said to be no restriction on the thickness of material used, which can be applied either by moulding or rotational casting.

Tel: +44 (0)1663 746518
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New vortex induced vibration suppression joints

Vortex induced vibration (VIV) is a common problem affecting underwater pipes. Water flowing around the pipe forms pockets of vortices which cause the pipe to vibrate from side to side, increasing in strength as the current and water flow increase in speed and resulting in more erratic movement in the pipe and possible damage.

In a bid to alleviate this problem, UWG has developed VIV suppression joints. The suppression system takes the form of tensioned cables coiled around the riser. These interrupt the water flow around the pipe and break up any vortices that might be caused. Elimination of the pipe vibration and associated movements on the surface improves the operational use of the riser and the life expectancy of both the riser and associated equipment, states the company, which, in turn, cuts costs.

The suppression joints are reported to have been successfully tested on subsea risers of small diameter (9⅝ inches) which are more prone to vibration, in areas of particularly high current speeds.

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NEW Publications and Data Services

DETR New Car Fuel Consumption and Emission Figures

(Available from Vehicle Certification Agency, 1 The Eastgate Office Centre, Eastgate Road, Bristol BS5 6XX, UK. Alternatively, view the guide at **www.roads.detr.gov.uk/vehicle/fuelcon/index.htm***)*

UK Minister for Transport, Helen Liddell, launched an easy access Internet guide for checking the environmental impact of new cars in July 1999. Previously only available in print, the Vehicle Certification Agency (VCA) new car fuel consumption and emission figures can now be reached on the Internet. Both versions of the guide also include information about pollutants which affect air quality and noise levels. Motorists can check their vehicle's emissions standard as well as how much noise and carbon dioxide it produces. The guide also reveals how much fuel motorists would need to drive 6,000 miles (10,000 km). 'This guide will make it easier for people to choose a car that is as clean and fuel efficient as possible,' comments Liddell. 'That's good news for consumers who can save money, and good news for the environment.'

Oil and Gas in Latin America: The New Era

(Available from the Centre for Global Energy Studies, Marketing Department, 17 Knightsbridge, London SW1X 7LY, UK). Price: £230 (£130 to conference delegates).

This publication contains the complete proceedings of the third CGES/CWC Latin America Conference held in Miami, Florida, on 3–4 March 1999. It includes a comprehensive introduction by Alirio Parra (Minister of Energy and Mines of Venezuela from 1992–94), full transcripts of all speeches and accompanying slides, open discussion sessions and biographies of all the speakers and session chairmen.

Caspian Oil at Eurasian Crossroads: Preliminary Study of Economic Prospects

A. Konoplianik (with A. Lobzhanidze) (Available from Kevin LaPierre; Tel: +1 617 498 9119; Fax: +1 617 441 6200). 53 pages. Price: $250. Available in both English and Russian.

This report is helpful to those who try to follow recent developments in the Caspian without the benefit of oil company data. The author, a former Deputy Minister of Energy for Russia and currently Adviser to the Russian Duma, uses detailed Russian data on reserves to estimate potential oil production from the Caspian. With estimates of transit costs from a variety of sources, and production cost estimates (at end 1998) he argues that the economics of Caspian oil developments are so finely balanced that the scope for transit fees, or even generous pipeline tariffs, is limited. His message is sobering: unless the companies introduce unforeseen technological improvements, leading to higher economic reserves, there will be limited oil available for export outside the Black Sea and the period of export surplus will be short. Major pipeline investments for export either through Turkey or through Russia will be difficult to justify economically.

Dr Konoplianik's view of what new technology can do may be conservative – new reserves may be discovered, recovery rates may be improved, creating larger production potential over a longer period. If an efficient construction and support industry were developed in Azerbaijan, with a higher proportion of costs incurred in local currency, competitiveness could be improved for the producers. Even so, the economics of a major export pipeline to supply Western Europe look doubtful compared with diversified exports to regional markets and through Iran to the more valuable Asian markets. The author's challenge remains – might not Russian and US interests be better served by their companies participating in a Caspian development strategy unconstrained by grand geopolitical designs?

Latest from the Library

Library reopened

The IP Library at 61 New Cavendish Street has reopened following refurbishment. Members are welcome to visit from 9.30am to 5pm, Monday to Friday (except Bank Holidays). Non-members may use the library facilities on payment of an entrance fee.

Recent additions to library stock

- *The Bulk Transfer of Dangerous Liquids and Gases Between Ship and Shore*. 2nd Edition. HSE Books, Norwich, Norfolk, UK, 1999.
- *Chemicals in the Oil Industry – Recent Developments.* Proceedings of the Sixth International Symposium on Chemistry in the Oil Industry, 14–17 April, Ambleside, Cumbria. L Cookson and P H Ogden (Eds). The Royal Society of Chemistry, Cambridge, UK, 1998.
- *Decommissioning the Brent Spar*. 1st Edition. T Rice and P Owen. E & FN Spon, London, UK, 1999.
- *Developments in Offshore Engineering: Wave Phenomena and Offshore Topics*. 1st Edition. J B Herbich (Ed). Gulf Publishing, Houston, Texas, US, 1999.
- *Economic Risk in Hydrocarbon Exploration*. I Lerche and J A MacKay. Academic Press, San Diego, California, US, 1999.
- *Gas to Europe: The Strategies of Four Major Suppliers*. R Mabro and I Wybrew-Bond (Eds). Oxford University Press, Oxford, UK, 1999.
- *Oil and Gas Infrastructure and Midstream Agreements: With Precedents*. M R David (Ed). Langham Legal Publishing, London, UK, 1999.
- *The Price of Oil: Corporate Responsibility and Human Rights Violations in Nigeria's Oil Producing Communities*. 1st Edition. Human Rights Watch, New York, US, 1999.
- *Strategies for Optimizing Petroleum Exploration: Evaluate Initial Potential and Forecast Reserves*. 1st Edition. L D Knoring, G V Chilingarian and M V Gorfunkel. Gulf Publishing, Houston, Texas, US, 1999.

New Periodical received

- *Tomorrow's Oil*. Petrodata.

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IP Conferences and Exhibitions

International Conference and Exhibition on

Offshore Marine Support (OMS '99)

Southampton: 12–13 October 1999

A joint IP/ABR Company Conference

The Conference will discuss developments in the offshore oil industry and the opportunities and challenges they present to marine support contractors in the coming decade. For the first time in many years, it will present a unique opportunity for naval architects, yards and vessel owners to present their capabilities and new ideas to the oil industry.

Exhibition and Sponsorship
An Exhibition of related equipment and services will be held in association with the Conference. To receive a copy of the Sponsorship and Exhibition brochure, please contact Sue Nixon in the IP Conference Department.

The programme and registration form is now available

International Conference on

The Re-use of Offshore Production Facilities

The Netherlands: 13–14 October 1999

Organised in association with the Association of Technology Transfer North Holland, Netherlands Energy Research Foundation (ECN), the IP Netherlands Branch, Aberdeen University Oil & Gas Institute and the Institute of Marine Engineers

The decommissioning of offshore facilities has been an emotive topic for the past couple of years. The debate has moved from dismantling to dumping, from recycling to recommissioning. The third in this series of international conferences, organised by the IP, focuses on the re-use of platforms and topside equipment.

The programme includes case histories and practical experience which will encourage companies to find alternative solutions to the disposal of redundant facilities.

The programme and registration form is now available

Workshop on

Health Effects of Fatigue on Performance

London: 21 October 1999

The Occupational and Environmental Medical Sub-Committee of the IP is organising this Workshop on the health effects of fatigue on performance. It will be restricted to 30 participants and will be of interest to health professionals in all sectors of the oil and related industries.

For more details or to book your place costing £100, please contact Jo Howard-Buxton at the IP on +44 (0)171 467 7127 or e-mail: jhb@instpet.co.uk

Business Seminar on

Opportunities in Canadian Oil and Gas

London: 9 November 1999 and Aberdeen: 11 November 1999

Supported by

The Canadian High Commission and *British Trade International*

The programme and registration form is now available

Autumn Lunch

Guest of Honour and Speaker: Dick Cheney
Chief Executive Officer, Halliburton Company, Former US Secretary of Defense 1989–93

Savoy Hotel, London: 15 November 1999

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

It is expected that many companies will purchase tables and maximise the opportunity to entertain guests at one of the key social events in the industry year.

The programme and registration form is now available

International Conference on

Developments in Measurement and Loss Control in Oil Refineries

London: 7–8 December 1999

The programme and registration form is now available

Training Courses

For further information and a copy of the programme of 1999 Training Courses, please contact Nick Wilkinson in the IP Conference Department.

IP Week 2000: 14–17 February

The IP Week 2000 Annual Dinner will be held on Wednesday 16 February at the Grosvenor House Hotel. Tickets are limited and members are therefore advised to book early to avoid disappointment. Please note that applications can only be made on the official ticket application form which will be published in the October edition of *Petroleum Review*.

Programmes and registration forms for all events are available from:

Pauline Ashby, Conference Administrator, at the Institute of Petroleum

Tel: +44 (0)171 467 7100 Fax: +44 (0)171 255 1472
e: pashby@petroleum.co.uk

Membership News

NEW MEMBERS

Dr M S Akhtar, MSE Consultants Limited
Mr J Alborough, Aberdeenshire
Mr H Allen, Ilkeston
Mr O O Aturu, London
Mr L R Battrick, Fakenham
Mr A T Bembridge, North Hykeham
Mr E Boling, United Airlines
Dr A R Bunn, Maidenhead
Mr F Bussandri, Futura Petroleum Limited
Mr P Clay, Canada
Mr M Danter, Shipton-by-Beningbrough
Mr S Davidson, Aberdeen
Mr N Davies, Inland Revenue
Dr J T Dawha, NNPC-Eleme Petrochemicalc Co Ltd
Mr J H Diesel, Anadarko Petroleum Corporation
Mr J Dolan, Nantwich
Mr L J Finnegan, Newbridge
Mr P A Ganley, Bristol
Mr A O Garuba, NNPC
Mr C R Grimm, Futura Petroleum Limited
Mr T Hall, Bayerische Landesbank
Mr C W Howard, Darlington
Ms A W Jones, Morgan Cole
Mr D D Kennedy, Futura Petroleum Limited
Dr J F Kenney, Gas Resources Corporation
Mr M Kothare, India
Ms S Lombardi, Futura Petroleum Limited
Dr D J B Maffin, GEC Marconi Power & Control Systems
Mr W McKenzie, Grimsby
Mr G Milne, Chrysalis Learning
Mr C W Mitchinson, Great Yarmouth
Mr V Moore, Canada
Mr S More, SGS India Limited
Mr E P Mothersdale, Crawcrook
Mr J-J Moungounda, UMSI Company
Mr C H Nurse, Aylesbury
Mr J Petracha, Inland Revenue
Mr S P A Piscina, Blackpool
Mr J Reekie, Twickenham
Mr G-J Reijnders, The Netherlands
Mr W Rowley, Ashford
Mr A Saeternes, Norway
Ms J Scott, Exxon Chemical Limited
Mr M Sherman, Middlesbrough
Ms M Sinha-Ray, London
Ms J Skinner, Inland Revenue
Dr M Smith, Granherne Limited
Mr N Stoodley, Cimcool Europe
Mr J E Stuart, Century Drilling Limited
Mr Y Turganaliyev, Kazakhstan
Mr J B Turner, Turner Power Systems Limited,
Mr C T J Van Den Nouland, The Netherlands

NEW STUDENTS

Mr N Froude, Bournemouth
Mr A Khan, West Bridgford
Mr M R Smith, Shrewsbury

STUDENT PRIZEWINNER

Mr D A Wright, Aberdeen

NEW FELLOW

Dr E T Libbey FInst Pet
Dr Libbey graduated from Cambridge University in 1969 with a BA in Chemistry (Class I). Fourteen years later he graduated from Harvard Business School with a PhD in Management Development Programming. Dr Libbey is a Director of Preng & Associates which is an Executive search company devoted exclusively to meeting needs of energy and utility (electricity) companies worldwide. Dr Libbey's personal responsibilities are focused on UK and European markets. Before joining Preng and Associates, Dr Libbey worked for two years as Manufacturing and Supply Director for BP Oil Europe.

NEW CORPORATES

Sutton & Son (St Helens) Ltd, Gorsey Lane, Widnes, Cheshire WA8 0FZ, UK
Tel: +44 (0)151 424 8108 Fax: +44 (0)151 420 6159
Representative: Mr Frank Merx
Carriage of hazardous chemicals and gases with plans to break into the petroleum products side of the industry. Based at Widnes, the company runs 350 vehicles, soon to reach 400 due to a contract with BP Chemicals. Operates from 10 locations in the UK and has offices on all continents.

D'urberville Developments Ltd, 12 Park Lane, Thatcham, Berkshire RG18 3PJ, UK
Tel: +44 (0)1635 860048 Fax: +44 (0)1635 872888
Representative: Mr Graeme McGivern
Retail premises maintenance contractor.

The July issue contained an entry for new corporate member Catalist. We must apologise for the errors contained in this entry and the amended details follow:

Catalist, Richmond House, 22 Richmond Hill, Clifton, Bristol BS8 1BA, UK
Tel: +44 (0)117 923 7113 Fax: +44 (0)117 923 7166
Representative: Mr Nigel Lang, Managing Director
Catalist maintains the definitive database of petrol stations. Eighty site details include brand, address, volumes, ownership, car wash, shop, market shares and digital photographs. GIS and Intranet services are also available. Catalist has formed a joint venture company with GMAP called Categy. The aim is to provide a benchmarking system for petrol stations, giving each site a rating based on its location and facility for fuel, car wash and QSR.

International meeting
IP PM-L-4 Marine Measurement Loss Committee
Oaxaca, Mexico, 9–11 November 1999

At the first meeting of this group to be held outside Europe, loss control specialists from most major oil companies together with representatives from inspection companies, terminal operators and tanker owners will be continuing their work related to understanding and controlling crude oil marine measurement and transportation losses. Panel B will meet on the first two days and having recently published a guideline document for crude oil washing and carriage temperatures will be continuing work on requirements for shipboard measurement equipment. Other topics for discussion include ROB/OBQ measurement and in-transit losses and there will be presentations from equipment manufacturers and terminal operators.

The marine loss database group, Panel A, will meet on 11 November for further discussion of the 1998 measurement data and to receive a report on vessel design characteristics related to reported measurement losses.

Potential new members are warmly invited to attend as observers although companies attending Day 3 should be producers or users of crude and in a position to submit data to the panel if they apply to join.

For details please contact John Phipps at the IP.
Tel +44 (0)171 467 7130, e: jp@petroleum.co.uk

EVENTS Forthcoming

SEPTEMBER

6–10 **Dundee**
Contracts in the Oil and Gas Industries: Negotiating and Drafting
Details: CEPMLP, University of Dundee
Tel: +44 (0)1382 344300
Fax: +44 (0)1382 322578
e: cpmlp@dundee.ac.uk

6 September
London: Aviation Workshop – *API Monogram Program for Filtration Equipment*
Details: Pauline Ashby, The Institute of Petroleum

7–8 **London**
Emissions Abatement Mechanisms for Major Energy Users and Producers
Details: Penny Richards, IBC Global Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e: cust.serv@ibcuk.co.uk

7–10 **Aberdeen**
Offshore Europe 99
Details: Offshore Europe Partnership
Tel: +44 (0)181 949 9222
Fax: +44 (0)181 949 8193

9 **Aberdeen**
Could your company survive below $10 a barrel oil? The role of supply chain and perfomance management
Details: Oracle Corporation
Tel: +44 (0)1224 626151
Fax: +44 (0)1224 626152
e: psparrow@uk.oracle.com

13–14 **New York**
Oil and Gas in Brazil
Details: Jonathan Neale, CWC Associates
Tel: +44 (0)171 704 6742
Fax: +44 (0)171 704 8440

13–17 **Fife**
UK Oil and Gas Law
Details: CEPMLP, University of Dundee
Tel: +44 (0)1382 344300
Fax: +44 (0)1382 322578

14 **London**
Information Management Through the Supply Chain
Details: IMechE
Tel: +44 (0)171 222 7899
Fax: +44 (0)171 222 4557
e: enquiries@imeche.org.uk
w: www.imeche.org.uk

15–17 **The Netherlands**
Reliability Conference: Oil, Petrochem, Power
Details: Global Technology Forum
Tel: +44 (0)1737 365100
Fax: +44 (0)1737 365101
e: events@gtforum.com

16–17 **London**
World Oil Prices
Details: Jonathan Neale, CWC Associates
Tel: +44 (0)171 704 6742
Fax: +44 (0)171 704 8440

16–17 **Geneva**
Petroleum Loss Control and Measurement Uncertainties
Details: GHB Consultant
Tel: +41 22 348 7378
Fax: +41 22 348 7978
e: ghbconsu@worldcom.ch

17–20 **Surrey, UK**
Oil Refining Course
Details: Petroleum Economist
Tel: +44 (0)171 831 5588
Fax: +44 (0)171 831 4567/5313

20–21 **Oxford**
1999 BIEE Conference
Details: Mary Scanlan, BIEE
Tel: +44 (0)181 997 3707
Fax: +44 (0)181 566 7674

20–21 **London**
Petroleum Trading and Cargo Shortages
Details: Abacus International
Tel: +44 (0)1245 328340
Fax: +44 (0)1245 323429
w: www.abacus-int.com

20–24 September
London: *Planning & Economics of Refinery Operations (PERO)*
Details: Pauline Ashby, The Institute of Petroleum

20–24 **Oxford, UK**
International Oil Supply, Transportation, Refining and Trading
Details: Jenny Butterworth, The College of Petroleum and Energy Studies
Tel: +44 (0)1865 260203
Fax: +44 (0)1865 791474
e: jenny@colpet.ac.uk

21–22 **London**
Knowledge Management in Energy
Details: Penny Richards, IBC Global Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e: cust.serv@ibcuk.co.uk
w: www.ibcglobal.com/eq149

22–23 **London**
Petroleum Trading and International Law
Details: Abacus International
Tel: +44 (0)1245 328340
Fax: +44 (0)1245 323429
w: www.abacus-int.com

22–23 **London**
Gas-to-Liquids
Details: SMi Customer Services
Tel: +44 (0)171 252 2222
Fax: +44 (0)171 252 2272

22–24 **Turkey**
Gas and Power in Turkey
Details: IBC Global Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e: cust.serv@ibcuk.co.uk

23–24 **London**
Meeting China's Oil and Gas Demand
Details: Jonathan Neale, CWC Associates
Tel: +44 (0)171 704 6742
Fax: +44 (0)171 704 8440
e: jneale@cwconferences.co.uk

27–28 **London**
Renewable Energy Finance Forum
Details: Euromoney
Tel: +44 (0)171 779 8008
Fax: +44 (0)171 779 8946

27–29 **London**
The European Bus and Clean Fuel Summit
Details: Alison Turtle, IQPC
Tel: +44 (0)171 430 7300
Fax: +44 (0)171 430 7301
e: bus.emissions@iqpc.co.uk

29 **London**
Managing and Exploiting Innovation Conference
Details: ERA Technology
Tel: +44 (0)1372 367125
Fax: +44 (0)1372 377927
e: conference@era.co.uk

29–30 **London**
An Introduction to Offshore Engineering
Details: Bentham Technical Training
Tel: +44 (0)171 436 7500
Fax: +44 (0)171 436 2112
e: v-li@bentham.com

OCTOBER

5–6 **Moscow**
Pipeline Projects in Russia and CIS
Details: Jonathan Neale, CWC Associates
Tel: +44 (0)171 704 6742
Fax: +44 (0)171 704 8440
e: jneale@cwconferences.co.u

IP Discussion Groups & Events

Energy, Economics, Environment

'Looking at future developments of hydrocarbon outlets in the eastern Caspian regions'

Tuesday 12 October, 17.00 for 17.30 until 19.00

Vittorio Jucker, Director Natural Resources Group, European Bank for Reconstruction & Development

IP Contact: Jenny Sandrock

London Branch

'Future role of independent storage in UK and Europe'

Thursday 14 October, 17.30 for 18.00

Richard Kellaway, Managing Director, ST Services Ltd

Tea will be served beforehand and light refreshments afterwards

Contact: Carol Reader +44 (0)181 852 9168

Energy, Economics, Environment

'What's so important about fuel prices?'

Thursday 28 October, 17.00 for 17.30 until 19.00

Steve Norris, Director General, The Road Haulage Association Ltd

IP Contact: Jenny Sandrock

Obituaries

Christopher M Dalley CMG 1913–1999

It is with sadness that the Institute of Petroleum reports the death of Christopher M Dalley who served as IP President from 1970 to 1972, following in his father's footsteps as IP President from 1942 to 1944. Educated at Epsom College and at Queen's College, Cambridge, he was recruited by the Anglo-Iranian Oil Company (later BP and now BP Amoco) in 1946 following six years' wartime service in the Royal Navy. Coincidentally, his father (also Christopher Dalley) had worked for Anglo-Iranian, acting as Chief Engineer in the 1920s.

Chris's first postings included Abadan, Iran, and the oil fields of Elk City in Oklahoma. He went on to spend most of the 1950s engaged in Middle East oil operations and was one of the few essential personnel permitted to stay in Iran following the expulsion of all foreign oil companies from the country in 1951. After the return of the Iranian Oil Operating Companies in 1954, he was heavily involved in the technical training and promotion of Iranian nationals to managerial positions within the company. Chris was awarded the Order of Homayoun for his services to the Iranian oil industry in 1960.

In 1963 he became Managing Director of Iraq Petroleum and was promoted to Chairman in 1970, a position from which he retired in 1973. Chris was awarded a CMG in 1971 in recognition of his 'delicate' negotiations which helped keep oil flowing after formal diplomatic relations broke down between Iraq and the UK.

After leaving Iraq Petroleum, Chris became Chairman of Oil Exploration Holding which later merged with the London and Scottish Marine Oil Company (Lasmo). He acted as Lasmo Director between 1979 and 1984. He served on a number of various industry bodies, including the Institute of Petroleum as President 1970–1972 and the Council of World Petroleum Congress. His charitable work included sitting on the Royal Medical Foundation (Epsom).

Our thoughts are with his wife, Elizabeth, son and three daughters.

Professor Laurence P Dake OBE 1941–1999

It is with regret that the Institute of Petroleum reports the death of Professor Laurence (Laurie) Dake. Graduating from the University of Glasgow with a degree in Natural Philosophy in 1964, Laurie began his career as a Petroleum Engineer with Shell International. Following a number of induction courses in various petroleum engineering subjects in The Hague, he moved into the international side of Shell's operations, working in the Netherlands, Australia, Brunei, Turkey and Venezuela. From 1971 to 1978 he was based in The Hague and spent a number of years in Shell's training centre where he taught graduates in the subject of reservoir engineering.

Laurie left Shell in 1978 – the same year that his first book, *The Fundamentals of Reservoir Engineering*, was published (many editions of which have since been published) – and returned to Scotland to join the newly established British National Oil Corporation as Chief Reservoir Engineer. He also became associated with the postgraduate Department of Petroleum Engineering at Heriot-Watt University where he served as an external examiner and taught reservoir engineering, later becoming an Honorary Professor of Petroleum Engineering.

Laurie left BNOC in 1982 and became an independent consultant based in Edinburgh. His contribution to the industry was acknowledged in 1987 when he was awarded an OBE for services to reservoir engineering. He published his second book – *The Practise of Reservoir Engineering* – in 1994.

In 1995, Laurie was honoured by the Society of Petroleum Engineers in the US which presented him with the Reservoir Engineering Award for distinguished contributions to petroleum engineering in the area of reservoir technology. He continued to present a number of courses to industry personnel – most recently teaching reservoir engineering to Shell employees in Nigeria – until passing away shortly before another planned course in Australia.

MOVES People

Jaakko Tuso, Licentiate in Technology, has been appointed Vice President, EU Affairs, of Fortum Oil and Gas Oy. He takes up the position on 1 October 1999.

Energy Africa has announced the appointment of **Dato' M Idris Mansor** as the new Chairman of the company following the resignation of **Rob Angel** in June this year. Mansor has been on the Board of Energy Africa since 1997 and is Senior Vice President of the exploration and production business of Petronas.

Amec plc has announced a new management structure under three business sectors: capital projects; services; and investments. Capital projects will be led by **David Robson**, the company's chief operating officer, with **Alan Lamerton** and **Roddy Grant** as Managing Directors. This sector will include Morse Diesel, Amec's US construction management business, headed by **Don Piser**. Services will be run by **Mike Straughen** as Managing Director, who will report to David Robson for operational matters and to Group Chief Executive **Peter Mason** for strategic development. Investments will continue to be led by **John Early**, the group's property and development director. The company's investment in SPIE SA remains the direct responsibility of Peter Mason.

Colin Allcard, until recently a Senior Manager with Shell, has been appointed Director of Channoil Consulting Services Ltd. With over 25 years' international experience in the downstream oil business, Allcard has held senior management positions in products and crude oil trading, fuels and lubricants marketing as well as general management, working in a wide range of cultures such as the Middle East, USA, the Far East and Africa.

Jim Truswell, joint proprietor of Truswell Haulage, has been elected Chairman of the Transport Association at the AGM held in London recently. Truswell has been a member of the Association for 10 years and considers his new role as an 'honour and challenge in a time of change for the industry'. He succeeds **Mr James Nuttal** of Nuttall's Transport of Rochdale.

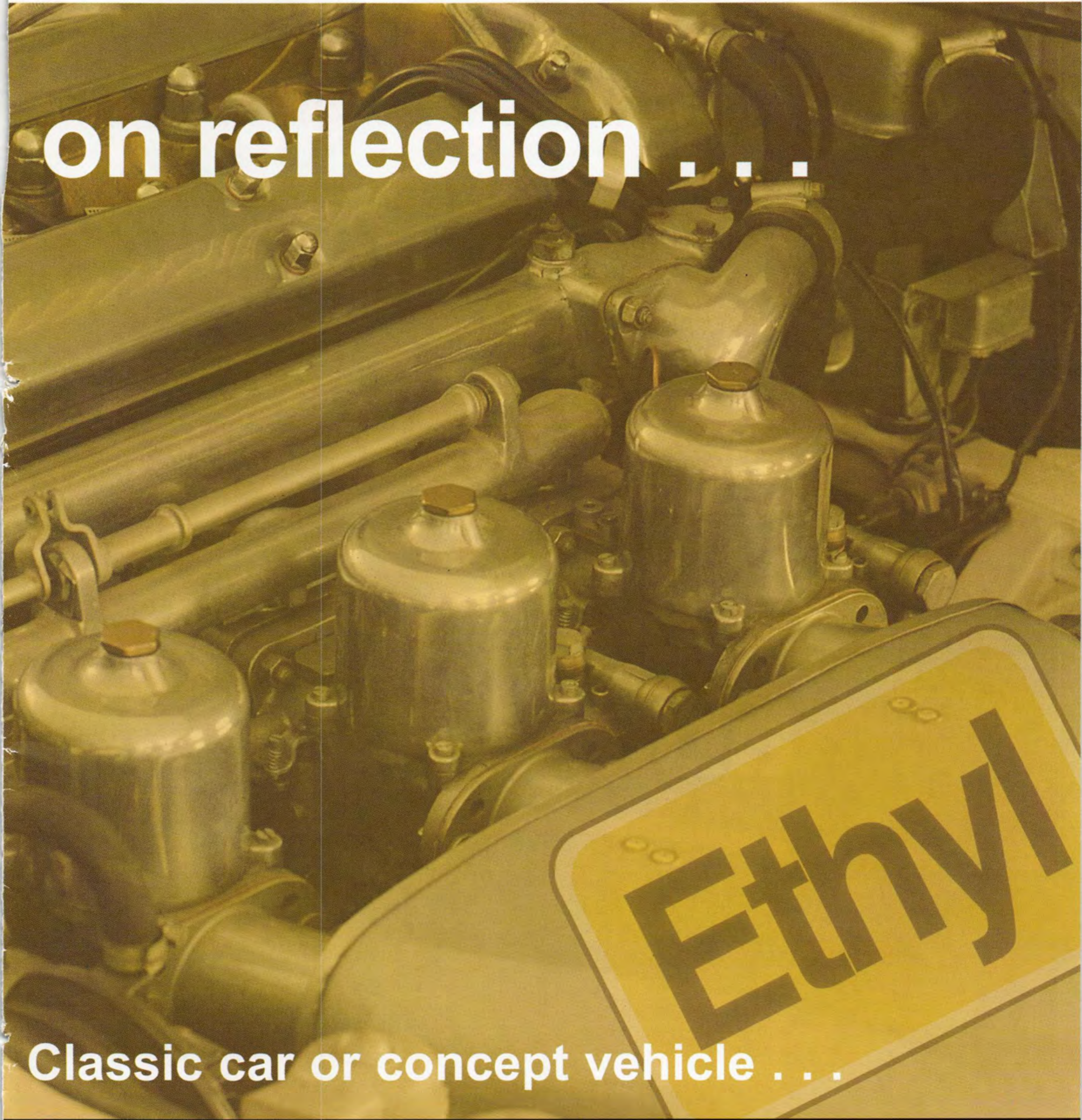
Roger Amstell has been appointed by Alderley Controls to head up its software department and build on the company's reputation for quality products and services. He brings to the company more than ten years' experience in software and computer development, latterly with Spectratek/Daniel Europe.

Moore Process Automation Solutions has recruited a new Projects Director, _Andrew Barbut_, to take overall responsibility for all turnkey process automation projects from concept to completion and into post hand-over support services. As a key member of the senior management team he will also ensure that a strategic overview is taken of all current and future projects.

Three new appointments have been made at tanker manufacturer Thompson Heil. _Bill McGawley_ (centre) as Managing Director is planning to expand the company's penetration into the European market. To assist this expansion, _Robin Harris_ (right) has been appointed Financial Director. The new Sales and Marketing Director is _Chris Dalton_ (left) whose responsibilities include managing the company's new repairs and aftermarket services.

David Looms has been appointed as new Managing Director of Balmoral Composites. Looms has extensive manufacturing experience in the plastics and rubber industry and was previously Managing Director of Darmag Industries in South Africa, a subsidiary of the Anglo American Corporation.

Dragon Oil has appointed **Ian Baron** as Chief Executive . Baron joins the company from Conoco Middle East where he held the positions of General Manager and Vice President.



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