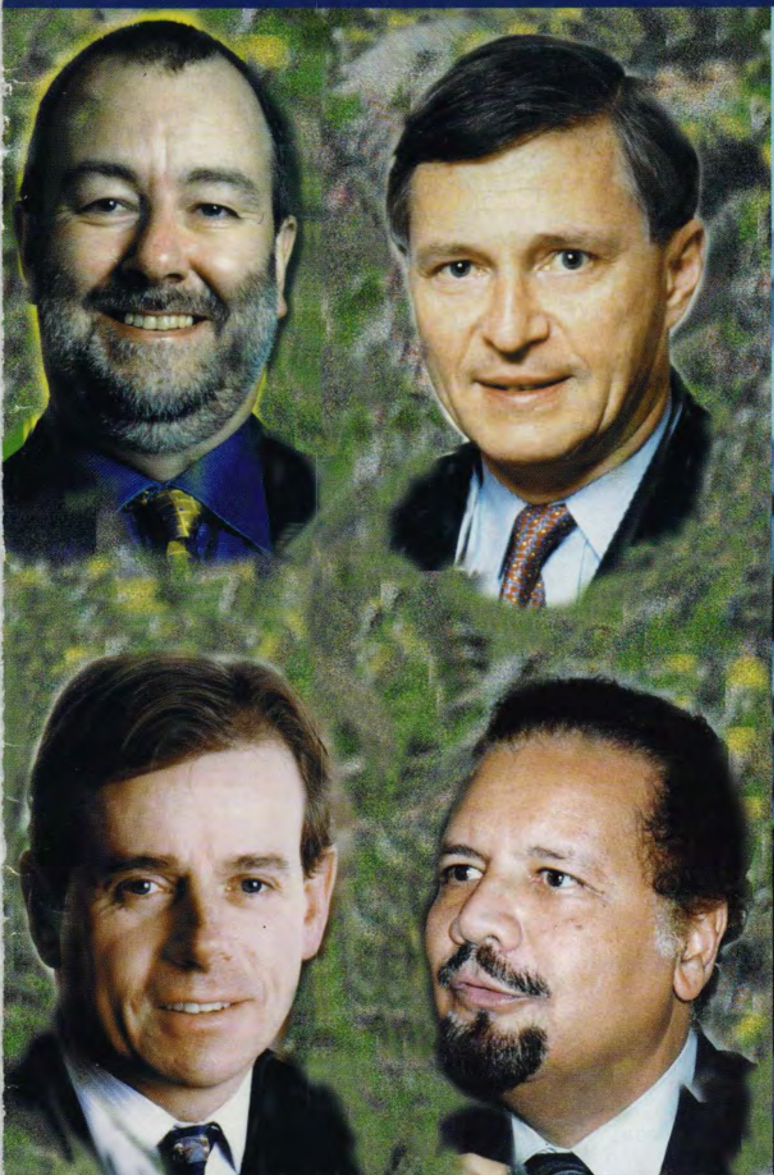
Petroleum review

FEBRUARY 2000



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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover: IP Week 2000. Leading industry figures will be speaking at the Commonwealth Institute, London, for the internationally renowned oil industry round of events.

Clockwise from top: Chris Moorhouse, IP President; Thierry Desmarest, President-Director General, TOTALFINA; Dr Richard C Ward, Chief Executive, IPE London; and HE Sheikh Yamani, Former Minister of Petroleum and Mineral Resources for Saudi Arabia (1962-1986)

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From the Editor

More oil developments needed?

It is very good news that industry confidence appears to be reviving, that 2000 E&P budgets look to be at least 10–15% above 1999 levels, and that prices remain very firm at around $25/b for Brent.

Less good is the fact that global oil stocks appear to be approaching the 'just-in-time' minima of late 1996, that Opec appears intensely reluctant to countenance production increases and the fact that there are remarkably few oil field projects due onstream in 2000.

Slashed E&P budgets in 1999 and 15 months of low oil prices have taken their toll and mean there are currently few projects to take off the shelf. In the UK sector of the North Sea (see p31) the only large capacity additions in 2000 are Elf's Elgin/Franklin and Shell's Shearwater projects, both of which are gas/condensate fields. Under what appears to be intense pressure from a UK Government increasingly worried by emptying construction yards, companies have announced a series of small, often single-well developments and two more substantial projects (see p3, 6 and 7).

For the last 20 years increases in non-Opec production have accounted for at least 60%, and sometimes 100%, of annual oil production growth. In the immediate future non-Opec production will be hard put to maintain the growth, effectively transferring more incremental demand to Opec.

It is always difficult to determine the amount of spare capacity Opec has, but what we do know is that if we sum the individual countries maximum output over the last two years it is around 30.25mn b/d of liquids (oil and NGLs). Recent Opec production has been running at around 29mn b/d, giving a capacity utilisation of the proven capacity of around 95%.

Alberto Corradi, ex-head of PdVSA, has recently claimed in print that Venezuela's production capacity has shrunk from 3.5mn b/d in 1997 to 2.9mn b/d now.

Focus on e-business

So far the only 'bug' to have affected oil company operations has been the flu, the computer one being notable by its absence.

The whole Millennium Bug saga has, however, given companies great confidence that their, all too often, newly audited and updated systems work and work well. It has also focused attention on companies' overwhelming dependence on computer systems. The smooth Millennium transition means that company boards can now focus their attention on e-business and e-business strategies.

Attitudes to IT now give investors clear hints as to whether the company is looking forward or back. The forward lookers follow Sir John Browne's view that IT is too important to be left to CFO's. They either have IT board members or report to the CEO. The others still have no board representation and are reporting to the CFO (presumably this follows the logic that the accountants bought and used the abacus, then the adding machine and, finally, the computer).

Taking the initiative

Shell has just announced a link with Commerce One to develop an industry e-procurement solution (see p15). The oil industry is now echoing the car industry, where Ford linked with Oracle to develop a company-based e-business solution to be followed by General Motors linking with Commerce One to develop a solution accessible to the industry. BP is developing a company-based solution, Shell and Commerce One an open solution for the industry. It will be fascinating to see which model is most successful.

E-procurement is, however, only the first stage – the real prize is low-cost, real-time control of the business. A good example is PetroCanada's day-to-day online control of production (see p16).

The Institute of Petroleum is organising an e-business conference on 11 April, entitled 'Digital Black Gold'. Speakers from key suppliers and users will develop the main e-business themes and the conference will be accompanied by an exhibition featuring a range of e-solutions. Those interested in participating should contact Pauline Ashby at the IP on +44 (0)20 7467 7106; e-mail: **pashby@petroleum.co.uk**

Its good to write

The editor is always pleased to receive and publish readers' letters. In this issue we have a most interesting proposal for the future pricing of North Sea oil (see p23). Comments about the magazine and its contents are greatly appreciated and help us with our planning our future issues.

Chris Skrebowski

Web World

UK downstream recruiter Oil Recruitment has launched its new website at **www.oilrecruitment.co.uk** Apart from providing candidates with details of jobs in trading, sales, general management, inspection, etc, it provides tips for interviewers and interviewees. There is also a survey of tanker drivers' wage rates.

It is becoming ever harder to track all the new websites for the energy industries. Riding to the rescue is 'Energy on the Web', subtitled 'A Guide to Online Resources'. This details and reviews over 200 energy related sites, bulletin boards and news groups. It is available for £395 from Financial Times Energy, Tel: +44 (0)20 7896 2241.

E-business (also p13–17)

The real boom this month has been in new e-business sites. **PetrolPlaza.com** claims to be 'the world Internet marketplace for the retail petroleum equipment industry'.

EnergyPrism.com, a business-to-business portal for the global petroleum industry, has announced the official launch on 25 January of its petroleum equipment and services e-commerce marketplace. The company's vision is to develop a large, online marketplace where petroleum-related companies can enter into a wide range of commercial transactions. **EnergyPrism.com** is currently enlisting oil companies and industry suppliers for its equipment auction market.

A new e-commerce service – **www.oil-buyer.co.uk** – is expected to enter its trial phase this month. Aimed primarily at industrial and commercial users, the system will provide a convenient way for buyers to source standard oil products from a range of suppliers in the UK. The developers are currently consulting with a number of interested parties and are be keen to hear from any suppliers who would like further details. Tel: +44 (0)1565 653293 or contact **nicksmith@oil-buyer.co.uk**

STOP PRESS: Statoil, the world's second-largest supplier of crude oil, and SAP have just announced that they are to co-develop the first open, global, online marketplace for the oil and gas industry – the **mySAP.com** marketplace.

Chevron and Ariba have unveiled Petrocosm Marketplace, claimed to be the first global, independent Internet marketplace to be owned by buyers and suppliers across the energy industry. Petrocosm Marketplace is planned to be an open Interet marketplace and exchange that will go live in the 2Q2000 at **www.petrocosm.com**

Go-ahead for Athabasca oil sand project

Shell Canada (60%), together with partners Western Oil Sands and Chevron Canada Resources (20% each), has been given the green light for the $2.4bn Athabasca oil sands project. The project is to produce 155,000 b/d of oil from oil sands in the Athabasca region of Alberta, western Canada, beginning in late 2002. Proven reserves currently stand at 1bn barrels.

Shell Canada is to invest $1.4bn through the joint venture and a further $300,000mn on modifications to its Scotford refinery, near Edmonton, to process feedstock. The other partners are to invest $1bn between them.

Third parties will supply additional facilities to the project, including a 500-km underground pipeline and two gas-fired co-generation plants.

The project will replace declining domestic production and help reduce North America's dependency on imported oil, generate more than $3bn in royalties and taxes, and create approximately 1,000 permanent operating jobs on-site for local people, claims Shell.

In oil sands mining a naturally occurring deposit of oil and sand is removed from just below the surface using mechanical shovels and trucks. This material is mixed with warm (30°C to 40°C) water and agitated to separate out the oil. The sand is then used to refill the mining pits. The Athabasca oil will then be sent through a 500-km underground pipeline linked to a new upgrader at Shell's Scotford refinery where, using hydrogen addition technology, it will be processed mainly into very-low sulfur, light synthetic crude. This will primarily be used to make high-quality transport fuels by Shell Canada, Chevron and other refiners in Canada and the US.

The project will use the latest low temperature extraction techniques and gas-fired co-generation to reduce energy use and will operate a closed-loop system to maximise the re-use of water, explains Shell. The use of hydrogen addition technology will ensure that no carbon-intensive coke is produced and keep emissions of sulfur dioxide to a minimum.

Hat-trick of North Sea projects from Shell Expro

Shell UK Exploration and Production has unveiled plans to invest more than £50mn in three existing Central North Sea developments – Curlew, Kingfisher and Gannet.

The Gannet field comprises a single platform, Gannet Alpha, linked to several satellite fields. Oil is carried via pipeline to Teesside, while gas is piped to St Fergus. Current production from the Gannet complex is 70,000 b/d. Shell plans to invest £25mn developing the second phase of the Gannet E field, following the success of what was claimed to be the world's longest electrical submersible pump tie-back installed in the first well. Phase 2 is due onstream in 3Q2000, producing 15,000 b/d.

Curlew comprises subsea developments tied back to the *Maersk Curlew* FPSO which is operated by Maersk. Oil is exported via shuttle tanker and gas by pipeline to St Fergus. Current oil production is 25,000 b/d. The next planned phase of development involves additional drilling and production from a newly evaluated reservoir adjacent to an existing known reservoir at a cost of around £12mn. If an economic reservoir is found, first production is expected in March 2000.

Kingfisher production is via a seabed manifold and pipeline system to the Brae B platform, operated by Marathon. Oil is exported via the Brae–Forties pipeline to Cruden Bay. Gas production is acquired by the Marathon-led Brae Group offshore. Current oil production is 16,000 b/d. The latest phase of development will involve drilling a horizontal well into a known reservoir which is below the reservoir currently producing at the field. The new development will produce via a subsea manifold incorporating HIPPS (high pressure integrity pressure protection system), which was installed as part of the original Kingfisher project. The new development is expected to cost more than £17mn with first production due in July 2000. Output is forecast to peak at 6,700 b/d of oil. The planned Kingfisher and Curlew projects are still subject to final approval from the UK Department of Trade and Industry.

The North Sea is a mature oil province in which it is increasingly unlikely that there will be many new big platforms needed in the future. According to Malcolm Brinded, Shell Expro Managing Director, these three incremental projects are 'examples of what is more likely to be the way ahead' – namely satellite developments tied back into existing infrastructure. 'Technological innovation means that some of these projects which were previously just not feasible are now within our grasp – and I am confident there will be more to come.'

In Brief

United Kingdom

Venture Production plans to acquire *Lasmo's 46.79% stake in North Sea block 16/12a and 25% interests in adjacent blocks 16/13b and c for an undisclosed sum. Block 16/12a contains the Birch and Larch fields, which are currently producing 8,000 b/d. Block 16/12a also contains the Pine and Elm oil discoveries.*

BP Amoco's Bell field in block 49/23 of *the North Sea has come onstream at an initial rate of 90mn cf/d of gas. Reserves are put at 94bn cf and are being exploited via a subsea tie-back to the Bessemer platform.*

GMT TXU Europe is understood to *have taken over operatorship of the Johnston gas field in the southern North Sea. The field is currently producing 62mn cf/d of gas and is estimated to have reserves of 198bn cf.*

Conoco is reported to be planning to *bring its Vixen gas field in southern North Sea block 49/17a onstream by October 2000. The field is to be developed as a single subsea well tied back to the Viking BD platform.*

Talisman Energy (UK) is reported to be *planning to drill a well on its North Sea Marcel prospect in a bid to boost the Beatrice field's falling production and extend field life which, at present, is due to end in 2001.*

BP Amoco – together with partners *BG, Amerada Hess, Phillips Petroleum, TotalFina and Agip UK – have announced that they are soon to begin a £71mn programme to develop an extension to the Lomond field in block 23/21 and the South Everest satellite field in blocks 2/9 and 22/10a of the North Sea.*

Texaco is understood to be selling its *34.5% stake in North Sea block 3/28a, 44.44% in block 9/11a, 62% in block 9/11b, and 62% in block 9/12c. It is understood that the company wants to sell the four interests, which contain the Bressay prospect and Mariner and East Mariner heavy oil finds, as a package.*

BG International is reported to be *planning to bring the Blake oil field, located in the Outer Moray Firth, onstream in August 2001. The field will be tied back to Talisman Energy's Ross field FPSO, the* Bleo Holm.

North Sea production high

Average daily oil output from the North Sea of 2.63mn b/d in the year to November 1999 was higher than in any other 12-month period since the mid-1980s, reports the latest Royal Bank of Scotland *Oil and Gas Index*. Prices were on the increase, as were revenues, states the report. Brent crude oil rose by almost 12% compared to October 1999, and then by 120% since November 1998. This meant that revenues – at £40.4mn/d – were 132% higher than November 1998.

Stephen Boyle, the Head of Business Economics at the Royal Bank, said: 'Although history wisely cautions against the folly of price forecasting, the likelihood is that Opec will decide to continue their production constraints at their next full meeting in March, leading to continued buoyancy in prices. While this will have only a limited effect at the petrol pump, it will feed through to the fuel costs of manufacturing and other business, and could put some upward pressure on inflation.'

Oil output increased by over 35,000 b/d in November, an increase of 1.3% on the month. Gas production rose during November by 31.2% – largely due to the seasonal demand for heating – but it was also up by 14.6% on November 1998. Combined output increased by almost 8% on the year.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Nov 1998	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	2,400,277	6,785	15.91
Jul	2,602,363	6,852	18.90
Aug	2,645,493	6,604	19.93
Sep	2,588,488	7,379	22.83
Oct	2,657,747	9,830	22.03
Nov	2,692,783	12,308	24.64

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Technological innovation boosts reserves

The key findings of a study into the impact of technological innovation on reserves growth, undertaken by Smith Rea Energy Associates and AEA Technology on behalf of the European Union, have been released. The study, which involved the analysis of over 240 field developments and redevelopments, reports that:

- The application of innovative technologies was reponsible for reserves gains on the North West European Continental Shelf of about 12.4bn boe over the period 1990–1997.
- Some 75% of the gains were attributed to innovations in three key areas – drilling, seismics and floating/subsea production (in that order). The gains resulted mainly from the 'enabling' of new fields.
- The gains have been accompanied by marked improvements in health, safety and environmental (HSE) protection.
- The potential for future reserves gains could be as much as an additional 19bn boe, accompanied by further improvements in HSE protection.
- EU technology support programmes have made a significant contribution to reserves gains (estimated at over 1.3bn boe in the period) and HSE improvements, and should continue to do so.
- The EU programmes are of particular value to SMEs by helping them to innovate and export in the face of fierce international competition.

In Brief

Europe

Statoil is understood to have reported *that an appraisal well drilled on the Mikkel licence has confirmed the southern extension of the field which the company states could now be developed as a commercial concern by 2003.*

Norsk Hydro is reported to be planning *to develop the North Sea Grane field via a platform at a cost of NKr15bn. First oil is expected in October 2003. Output will be shipped via pipeline to the Sture terminal. Production is expected to peak at 214,000 b/d by 2005. Field reserves are put at 700mn barrels of oil.*

The Norwegian authorities are *reported to have approved Norsk Hydro's NKr2.5bn plan to develop the Tune gas/condensate field as a satellite to the Oseberg field complex in the North Sea. First production is expected in 2002. Field reserves are put at 27bn cm of gas and 7mn cm of condensate.*

The Norwegian Oil and Energy *Ministry is reported to have awarded Norsk Hydro operatorship of the development phase of the Ormen Lange gas field in the North Sea. Shell is to take over operatorship of the project once production begins in 2006 at the earliest. Reserves are put at around 300bn to 400bn cm of gas.*

North America

Unocal is understood to have reported *a 'significant' natural gas find on Ship Shoal block 295 in the Gulf of Mexico.*

Santa Fe Snyder is reported to have *acquired an additional 33% stake in the Gulf of Mexico Angus/Manatee complex – bringing its total working interest in Shell-operated field to 49% – from Marathon Oil for $160mn.*

The Sable Offshore Energy Project off- *shore Nova Scotia is reported to have delivered first sales gas into the Martimes and Northeast Pipeline. Initial production from the project has averaged 100mn cf/d and is expected to reach over 500mn cf/d this year.*

Conoco Canada is reported to have *doubled the size of its portfolio following the acquisition of 272bn cf of proven gas reserves from Renaissance Energy for an undisclosed sum.*

LOGIC-al look at supply chain management

The UK Oil and Gas Industry Taskforce has unveiled a new 'Optimising Supply Chains' toolkit aimed at 'revolutionising supply chain management throughout the oil and gas industry' under its LOGIC (Leading Oil and Gas Industry Competitiveness) initiative (see *Petroleum Review*, October 1999).

The package includes an assessment framework and a practical toolkit designed to help players in both the contracting and operating sectors to acquire the knowledge and skills required to 'excel at managing supply chains'.

According to LOGIC Chairman, Al Bolea: 'The economic pressures facing the oil and gas industry make it more important than ever for companies large and small to get involved and take up the challenge of improving competitiveness. The starter pack will help people reinforce the need for change within their own organisations and promote new ways of working. Briefings will be followed by an assessment framework designed to identify areas for improvement in supply chain practices. From this diagnostic process, companies will be able to draw up clear action plans to make the improvements that have been identified. Finally, the toolkit provided by LOGIC will help put the plan into action, analyse the supply chain and develop strategy. LOGIC staff will help kick-start the work within companies and review outputs.'

Go-ahead for Ceiba field

The Government of Equatorial Guinea has approved Triton Energy (operator) and Energy Africa's development plan for the offshore Ceiba oil field located in blocks G and F in the Rio Muni Basin. Phase 1 development via an FPSO is expected to produce 52,000 b/d of oil by the end of the year.

The FPSO-based project has been designed to allow for the accelerated development of the field. The FPSO will provide storage for 2mn barrels of oil, with an initial processing capacity of up to 60,000 b/d. This could be expanded with incremental processing capacity to accommodate up to 240,000 b/d when necessary, states Triton.

Four subsea production wells are to be connected to the FPSO in Phase 1 of development. The Ceiba-1 discovery well and Ceiba-2 appraisal well are scheduled for completion work in 2000 and will be two of the four planned producing wells. Drilling and completion of the remaining two appraisal/production wells is planned during the year.

UKCS tax collection change

A draft Contracting Out Order which will permit the transfer of revenue collection from the UK Department of Trade and Industry's (DTI) Oil and Gas Royalties Office (OGRO) to the Inland Revenue's Oil Taxation Office (OTO) has been unveiled by Energy Minister Helen Liddell.

Currently, the administration of government revenues from UK Continental Shelf production is split between the DTI and Inland Revenue – DTI handling the 12.5% royalty payments on oil and gas produced from pre-April 1982 fields and the OTO administering Petroleum Revenue Tax (PRT) and corporation tax.

It is understood that the proposed rationalisation should bring significant benefits to producer companies. The intention is that the administration of PRT and oil and gas royalties will, with industry input, be conformed in order to bring a more streamlined service. OGRO and the OTO have different skill bases and the expectation is that both will gain from further integration.

Major deepwater find offshore West Africa

Texaco has reported that the Agbami-2 discovery well drilled on the Agbami field offshore Nigeria has 'surpassed expectations' and that field reserves could be in excess of 1bn boe – ranking it among the largest single finds to date in deepwater West Africa.

The Agbami field structure spans an area of 45,000 acres and extends from block 216 into block 217. Texaco's share of production from the resource is expected to exceed 50%.

The Agbami-2 well located in block 216 was drilled in 4,800 ft of water to a total depth of 15,683 ft. The well encountered 534 ft of pay in five separate oil-bearing zones, one of which flowed at a maximum rate of 10,000 b/d of 45° API sweet crude with no contaminants.

Further delineation wells are planned to be drilled this year. It is proposed to bring Agbami onstream in 2H2003, with peak production of 200,000 boe/d from 10 producing wells and three injection wells targeted by 2004.

In Brief

Statoil is reported to have sold the explo*ration and production division of its US subsidiary Statoil Energy to Pittsburgh, Pennsylvania-based Equitable Resources for $630mn.*

Texaco is understood to have granted *McMoRan Exploration the right to explore all or parts of 90 of the oil major's Gulf of Mexico tracts in the outer continental shelf. McMoRan has committed to invest more than $100mn on exploration in the region over the next four years.*

Texaco is reported to have announced *a $4.7bn exploration budget for 2000, some 20% higher than its 1999 budget.*

Canadian Occidental Petroleum is *reported to be planning to spend $335mn of its $850mn capital expenditure budget on exploration in 2000.*

Middle East

Gaz de France subsidiary Sofrefaz is *carrying out a feasibility study on converting the depleted Sarajeh gas field near Tehran into a gas storage facility, reports* Stella Zenkovich. *The 2bn cm capacity facility would help prevent gas supply disruption in the Iranian capital in winter.*

Russia & Central Asia

The Turkmen authorities plan to pro*duce 10mn tonnes of oil and 46.5bn cm of gas in 2000.*

The production sharing agreement *(PSA) for Shell International and Anglo Siberian's Vankorskoye field has been given final approval by the Russian authorities. Field reserves are put at 906mn barrels of oil and 2.6tn cf of gas.*

Lukoil is reported to be planning to *invest $36mn developing the 150mn tonnes of oil reserves in the North Pukachevskovo, South Vyentoyskovo and Talnikovskaya fields in west Siberia in 2000.*

Asia-Pacific

Pakistan's Oil and Gas Development *Company and Zaver Petroleum are reported to have discovered hydrocarbon deposits in the Shakardara block – said to be the first such find in the North Western Frontier Province.*

Angola's first deepwater oil field onstream

Crude oil production has begun from Angola's first deepwater oil field – Kuito – in offshore block 14 in the Cabinda Province. Output from the Chevron-operated field, combined with ongoing production from block 0, has raised Chevron-led production in Angola to what is claimed to be a record level of 519,000 b/d. Kuito, which was brought onstream under budget, is expected to reach peak production of 100,000 b/d by the end of 1Q2000.

In the initial phase of development, 12 subsea wells will produce crude oil for processing to the 1.4mn barrel storage capacity *Kuito* FPSO, which has been chartered from Sonasing, a joint venture operation between Sonangol and SBM Production Contractors. The vessel is designed to process 120,000 b/d of fluids. Crude will be pumped, via a separate floating buoy, into tankers for export. A subsea water injection system, installed in conjunction with the initial subsea production system and controlled onboard the FPSO, will enhance field production from mid-2000. There is to be no flaring of natural gas, which is present in the reservoir and produced in association with the crude oil. Instead, the gas will be either used as fuel for the FPSO or reinjected into the reservoir.

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

Australian acreage to be awarded

The Australian Department of Industry, Science and Resources recently launched an initiative under which offshore exploration areas not taken up as permits during the normal acreage release process are promptly re-released. It is hoped that such a process will provide greater flexibility in the operation of the work programme bidding system, enable industry to increase an unsuccessful bid, give seismic survey companies an extended opportunity to market non-exclusive seismic data to potential purchasers and enable companies that have had a permit cancelled to maintain 'good standing' by undertaking offsetting exploration in permits gained through the re-release process.

Areas which did not receive successful bids in the 1999 release round, applications for which closed on 14 October 1999, include five areas offshore Western Australia, two areas offshore South Australia, one offshore Victoria, six offshore the Northern Territory and two offshore the Territory of Ashmore and Cartier Islands. These areas will now remain open for applications until 6 April 2000.

Planning for the next release of offshore exploration is reported to be well advanced with 87 new areas under consideration. These include the Petrel Sub-basin (offshore Northern Territory and Western Australia); Ashmore Platform, Vulcan Sub-basin and Londonderry High (adjacent to Ashmore/Cartier Islands); Northern Browse Basin, Canning Basin, Exmouth Plateau/Barrow Sub-basin, Dampier/Beagle Sub-basin and Perth Basin (offshore Western Australia); Otway Basin (offshore Victoria); Gippsland Basin (offshore Victoria/Tasmania); and the Bamaga Basin (offshore Queensland). Most of the areas have received some exploration in the past, but many are only lightly drilled and most fall within the under-explored category.

Karachaganak output up

The Karachaganak Consortium comprising Lukoil, BG, Eni and Texaco has posted an 81% increase in gas condensate production to 3.80mn tonnes and a 74% rise in natural gas output to 4bn cm, reports the United Financial Group's *Russia Morning Comment*. The Karachaganak field has reserves of 300mn tonnes of gas condensate and 1,800bn cm of natural gas. It is in the early stages of development and, as a result, the double-digit growth figures are not surprising, comments UFG.

UFG also points out that development to date has been achieved without a main pipeline being available, and suggests that production may increase even more quickly following the commissioning of the Caspian pipeline in 2001.

Green light for Keith field

BHP and partners in North Sea block 9/8a have been given the green light by the UK Government to develop the Keith oil field. The field – which has proved and probable reserves put at 15mn boe – lies close to the BP Amoco-operated Bruce oil field in which BHP has a 16% interest. Its subsea development will involve the re-use of a suspended appraisal well, 9/8a-14, which will be tied back to the Bruce Western Area Development (WAD).

Drilling is expected to begin in 3Q2000, with first oil targeted for the end of 2000.

Field partners are: BHP (operator, 31.83%), BP Amoco (34.83%), Elf Exploration (23.33%), Veba Oil & Gas (8.33%) and Total Oil Marine (1.67%).

In Brief

State oil and gas monopoly *Petrovietnam and Zarubezhneft of Russia – which is currently building what is said to be Vietnam's first oil refinery – have formed a 50:50 oil exploration joint venture to be known as Vietsovpetro, reports* Stella Zenkovich. *Russian company Gazprom, too, is reported to be setting up a joint venture with Petrovietnam to explore and develop gas reserves in the Gulf of Tonkin. Meanwhile, a consortium of Petrovietnam, US company Amoco and Statoil of Norway have commenced construction of the long-delayed $400mn, 390 km pipeline to pump gas from the offhore Lan Tay (West Orchid) and Lan Do (Red Orchid) fields from block 6-1 of the Nam Con Son project offshore southern Vietnam.*

Shell and Cairn Energy are reported to *have discovered an extension to the offshore Sangu gas field in India's Bay of Bengal. The Sangu field has estimated reserves of 1tn cf and is currently producing 130,000mn cfld of gas.*

The Pakistan authorities have given *British-Borneo and partners the green light to develop the Miano gas field in the Sindh province. First oil is expected in1Q2001. Reserves are put at 375mn cf.*

A consortium of Reliance Industries *and Niko Resources of Canada are reported to have secured 12 of the 25 oil exploration blocks recently awarded by the Indian Government under its new exploration and licensing policy. State-owned Oil and Natural Gas Corporation (ONGC) won eight blocks out of the 15 it had bid for. Other successful bidders included Cairn Energy and Oil India.*

The Indian Government is understood *to have given the go-ahead to Gujarat State Petroleum Corporation for development of the North Balol, Unawa, Dholasan, North Kathana, Kanawara and Allora oil fields in Gujarat state in western India.*

Chevron has announced the discovery *of 'potentially significant' hydrocarbon deposits in the Jarmjuree area of block B8/32 in the Gulf of Thailand. The company is to apply for a production licence area to develop the reserves.*

Chevron is to take over operation of oil *and gas upstream assets previously operated by Wapet (West Australian Petroleum) – including the producing Barrow Island and Thevenard Island oil fields in Australia – in which it has a stake.*

Chevron unveils E&P plans for 2000

Chevron has announced a $5.2bn capital and exploration spending programme for 2000. The company reports that the 2000 plan is 16.5% less than estimated actual 1999 spending. However, it is worth noting that in 1999 the company acquired Rutherford Moran Oil Group (whose assets include operatorship of block B8/32 in the Gulf of Thailand) and Argentinian E&P company Petrolera Argentina San Jorge.

The company plans to invest $3.6bn, or 69% of total 2000 spending, in worldwide exploration and production. Spending in the US will be $1.3bn. The worldwide programme includes funding for growth projects in:

- Kazakhstan – boosting average production from the Tengiz field from 215,000 b/d to 260,000 b/d this summer.
- Africa – where Chevron has steadily increased production from Angola and Nigeria. Angolan output recently reached a record 519,000 b/d, boosted in December 1999 by the start-up of the deepwater Kuito field, which is already producing 50,000 b/d.
- Thailand – where gross production from block B8/32 recently reached 150mn cf/d of gas and 24,000 b/d of liquids.
- US – where deepwater gross production reached 98,000 b/d of oil and equivalent gas from the Gemini and Genesis fields at year-end 1999. The development of a third project, Typhoon, is due onstream in mid-2001.
- Canada – where the company has a 20% stake in the Athabasca oil sands project which is targeted to produce 155,000 b/d of bitumen for upgrading to high-quality synthetic crude oil. First production is due in late-2002 (see p3).

The company also plans to invest about $830mn in worldwide refining and marketing, of which $350mn will be spent in the US. It also plans to invest just over $200mn in the worldwide chemicals business in 2000 – roughly half the rate in 1999, following completion of several major projects.

Jade plan approved

The UK Government has approved Phillips Petroleum's development plan for the North Sea Jade field. First production is due in 4Q2001 with output forecast to plateau at 16,000 b/d of oil and 188mn cf/d of gas. Gas is to be transported via the Judy platform and the CATS pipeline to the Teesside terminal. Oil will be exported via the Norpipe system to Phillips' Seal Sands terminal, also on Teesside. Reserves are put at 40mn barrels of condensate and 350bn cf of gas.

Kvaerner Oil and Gas's Methil yard is to build the Jade platform while Heerema's Hartlepool yard will build the 2,100-tonnes topsides. Amec has won the engineering, design and procurement contract, which includes topside facilities and pipeline risers for the Jade platform and associated modifications to Judy, its host platform.

Kyle extended well test

PGS Golar Nor is to provide the *Petrojarl 1* FPSO vessel for an extended well test (EWT) during the Phase 1 development of the North Sea Kyle field. The EWT is subject to the approval of the UK Department of Trade and Industry and consideration of an environmental statement. It is due to commence production in late May 2000 from the 29/2c-12z well at rates expected to be in excess of 10,000 b/d for a period of four to five months.

Various options are under consideration for the continued development of Kyle following the EWT, including the use of the *Ramform Banff*.

Kyle field partners are: Ranger Oil (operator, 40%), Premier Pict Petroleum (35%), ROC Oil (11.25%), Bow Valley Petroleum (11.25%) and Croft Exploration (2.5%).

Green light for Blake project

The UK Government has given BG International and partners the green light for development of the Blake field in the Outer Moray Firth.

The field is to be developed via a subsea tie-back to the nearby Ross field's *Bleo Holm* FPSO. The £158mn project is expected to 'significantly increase' the Ross field's economic life.

Output from six Blake production wells will be commingled with the Ross fluids on the FPSO for export by shuttle tanker. Gas will be transported via the existing connection to the Frigg gas pipeline.

First oil is due in August 2001 and is expected to peak at 40,000 b/d. Recoverable reserves are put at between 50mn and 75mn barrels.

Field partners are: BG International (44%), Talisman Energy (53.6%) and Paladin Resources (2.4%).

In Brief

Unocal is understood to have made its *third major gas field discovery in Bangladesh –the Moulavi Bazar field in block 14. The new field has tested between 23mn cf/d and 30mn cf/d.*

Zarubezhneft of Russia is understood *to be planning to develop the Dai Hung, N9 and N14 fields in Vietnam.*

Shell is reported to have agreed the *sale of 10% of its 55% stake in the southern Philippines Camago-Malampaya natural gas project to state company PNOC Exploration in a deal some industry pundits have valued at $200mn. Texaco holds the remaining 45% in the field which is due onstream in 2001. Production is forecast to peak at 360mn cf/d of gas in 2002.*

Latin America

Chevron is to partner Petrobras in a *50:50 exploration venture in deepwater blocks BC-20 and BCUM-100 in the Campos Basin and Cumurtuxatiba Basin, in Brazil's prolific Salt Basin.*

ExxonMobil's production of heavy oil *from the Cerro Negro area of Venezuela's Orinoco belt is reported to have come onstream at 60,000 b/d. Production is to double in 2001.*

Africa

Sonatrach of Algeria is reported to be *evaluating six bids for the construction of a $1bn crude oil pipeline which is to expand the capacity of the corridor linking the central Haoud el-Hamra oil fields to the Arzew terminal, west of Algiers. Two 400-km, 34-inch diameter pipelines are planned at a cost of between $220mn and $250mn each. A $400mn pumping station is also to be built.*

US company Drucker Industries is *reported to have commenced oil sales from the Hana field onshore Egypt. Initial deliveries are averaging 3,000 b/d – a figure expected to double in 2000.*

Tuskar Resources has announced that *the Obe No 4 well in OML 110 offshore Nigeria has produced first oil via the* Crystal Sea *FPSO.*

Elf Exploration Angola and Sonangol, *the Angolan national oil company, have reported their eighth new oil discovery in deep offshore block 17. The Camelia 1 well tested at 9,000 b/d of oil.*

NEWS Industry — In Brief

World Trade Organisation trade talk complications

Prospects for a smooth launch of fresh international trade negotiations that could have led to the liberalisation of energy production and distribution were derailed by the collapse of the recent World Trade Organisation's (WTO) ministerial meeting in Seattle, US, reports *Keith Nuthall*.

The meeting broke up without governments agreeing to launch an all-embracing trade round that would have included goods and services, as well as discussions on electronic commerce and intellectual property rights.

Under the existing WTO Marrakesh agreement, limited rounds on services and agriculture were still due to be launched in January and the WTO's General Council was to meet on 17 December 1999 to formally sanction them. Under the WTO's rules, oil and gas transportation and distribution are considered services, so the talks would be relevant to the petroleum industry.

But even if – as expected – the talks on services go ahead, the fact that the ministerial meeting failed to agree terms of reference for any trade talks will lead to the negotiations being slowed down, although difficulties would probably not prove to be intense.

There was little discord at Seattle over services, where a consensus said that all sectors should be discussed and that they should aim at further liberalisation.

Under the WTO system, there is wide scope to reduce trading barriers which impede the flow of energy services around the world. During negotiations, member countries make commitments to the opening various sectors of their economies to foreign competition – there are comparatively few in the energy sector, affecting:

- pipeline transportation of fuels;
- services incidental to energy distribution; and
- services incidental to mining.

Only three countries have commited themselves to opening their pipeline services to foreign companies – Australia, Hungary and New Zealand. Meanwhile, eight have commitments in services incidental to energy distribution and 33 in services incidental to mining.

Shell announces new finance targets

Shell Chairman Mark Moody-Stuart reported mid-December that the company had 'achieved better than expected' cost improvements in 1999, including exploration expense savings of $1.8bn. 'We now anticipate $4bn in 2001,' he said. 'We've already trimmed capital investment from $15.7bn in 1998 to $10bn currently; and we have announced portfolio rationalisations for 1999 of $12bn... of which $8bn is completed or contracted.'

Moody-Stuart also pointed out that portfolio changes in Chemicals were well on target, with $4.4bn completed or contracted, and forecast a reduction of capital employed in the business of $5.7bn, or more than 40% by the 1H2000.

He also reaffirmed the company's commitment to a group return on average capital employed (ROACE) target of 14% by 2001, assuming an oil price of $14/barrel.

Surgutneftegaz outlines plans for 2000

Surgutneftegaz has announced its 2000 operating targets, reports the United Financial Group's *Russia Morning Comment*. The Russian company plans to increase oil production by 3% to 38.6mn tonnes in 2000 compared with 37.6mn tonnes in 1999, and to reduce gas production by 8% to 11bn cm.

Refining output is targeted to reduce by 2% to 17mn tonnes.

UFG comments that the crude oil production figures may be 'too conservative' given that the company's 4Q1999 results imply annual production of at least 38.9mn tonnes, which is already higher than the company's 2000 forecast.

Furthermore, a proposed 7% increase in development drilling (exploration drilling to rise by 21%) will also lead to an increase in production.

Capex is expected to rise by 35% in terms of US dollars in 2000, from $510mn to $689mn. This is not only due to higher drilling volumes, but also to the large amount of planned investments in upgrading the Kirishi refinery, comments UFG.

Upon completion of a share swap, Surgutneftegaz will be able to legitimately use cashflows from upstream operations to invest in refining, as it will become the sole owner of Kirishi.

United Kingdom

Stolt Comex Seaway (SCS) of Aberdeen *is reported to have bought French offshore construction and engineering business ETPM from parent Group GTM for $130mn in cash and 6.1mn SCS Class A shares. The total deal is worth over $300mn.*

Conoco is rumoured to be considering *making a £2.5bn takeover bid for UK independent Lasmo. No further information is available.*

Europe

Eni, through its subsidiaries AgipPetroli, *Snam and Italgas, is to acquire a 33.34% shareholding in Portuguese company Galp (Petroleos e Gas de Portugal).*

German utilities Viag and Veba are *understood to be seeking regulator and shareholder approval for a planned merger in early 2000.*

North America

BP Amoco and Arco met US Federal *Trade Commission (FTC) in January to discuss the next steps in their proposed merger. The FTC is reported to still be blocking the deal due to concerns regarding the new company's dominant position in Alaskan oil production.*

ExxonMobil has unveiled plans to cut *nearly 16,000 jobs in a bid to save $3.8bn by the third year of the merger. The company also reported that it expects the merger to raise net income by $1bn in 2000, and by $2.5bn in 2003.*

Russia & Central Asia

Vagit Alekperod has resigned as *Chairman of Lukoil.*

Mikhail Gutseriyev, a former MP from *the LDPR faction of the Russian Duma, has been elected CEO of Slavneft.*

Transneft, now owned by Lukoil, has *proposed a 45% pipeline tariff increase for both domestic and export deliveries.*

General

The Opec Monitoring Committee has *proposed an extension of the current reduction in oil output by Opec and non-Opec members beyond March 2000.*

In Brief

Benefits of bottom loading

Q8 Fuelcare's southern England depot at Edenbridge has invested £200,000 in bottom loading technology and a fleet of bottom loading ERF road tankers in order to comply with new 'sealed parcel' regulations requiring all road tankers to be bottom loading which came into effect in January 2000.

The new ERF ES6 four-wheel tankers have been commissioned in a slim-line model with a chassis some seven inches narrower than standard tankers in order to facilitate fuel deliveries 'to the most difficult of locations', states the company.

The new bottom loading technology at the depot not only reduces the risk of static discharge while loading, but is more efficient and significantly reduces loading and unloading times, comments Paul Bogaers, Q8 Fuelcare South Regional Manager.

Four star fuel service from Thrust

The sale of unleaded petrol was banned from UK forecourts on 1 January 2000 and has been replaced by sales of lead replacement petrol (LRP) (see *Petroleum Review*, September 1999). However, following lobbying by various bodies including the Federation of British Historic Vehicle Clubs (FBHVC), a derogation to the EU Directive was agreed which stipulated that a small amount of leaded fuel would be made available to meet the needs of 'special interest groups' such as classic car clubs and the racing fraternity.

Independent fuel retailer Bayford Thrust reports that it is the only petroleum company to have obtained a permit from the Department of Environment, Transport and the Regions (DETR) to distribute leaded fuel UK-wide and has secured 82% of the total 100mn litre allocation under the derogation.

The fuel will be manufactured by Futura Petroleum (an operating subsidiary of Finnish energy group Fortum Oil and Gas) and distributed by Bayford through the Thrust retail network, Thrust franchise distributors and independent forecourts. One Thrust franchise distributor, BWOC, has also secured a permit for distribution of the fuel in the southwest of England.

'As independent oil companies and petrol retailers, we have to be innovative and take the initiative,' comments Jonathan Turner of Bayford Thrust. 'That's what we are and that's what we've done. We are now looking for independent petrol retailers across the country who are keen to take advantage of this opportunity.'

Retailers have to become members of the FBHVC, which costs £50. Once registered as members and the leaded fuel has been delivered by Bayford Thrust, the address of the retailer will be publicised by the media and on the Bayford Thrust (**www.bayfordthrust.co.uk**) and Futura (**www.futura-petroleum.com**) websites.

Some of the fuel retail outlets have strict contracts in place and it has yet to be seen what view the existing supplier will take regarding the supply of leaded fuel from another organisation. However, according to Turner, 'if the site is subject to an existing supply contract we will not supply leaded petrol without the authorisation of that supplier.'

United Kingdom

Texaco is reported to be on the brink *of announcing a £30mn takeover of Conoco's 625-strong Jet-branded service station network in the UK. If successful, the deal would increase Texaco's network to over 2,000 sites, giving it a 12% marketshare by volume of fuel sales.*

Shell is reported to have agreed an 18- *year lease and leaseback deal with London & Regional Properties covering 180 of Shell's 1,400-strong service station network for £300mn.*

UK Energy Minister, Helen Liddell, has *given the go-ahead to EniChem UK and ScottishPower to build a 45-MW gas-fired combined heat and power station at Hythe in Hampshire. She turned down an application for a 100-MW gas-fired power station at Britannia Zinc, Avonmouth, stating that it was not in accordance with the government's stricter power station consents policy.*

Texaco has acquired 10 new service sta- *tions in the UK as part of a lease agreement with Ellwood's Garages. The deal adds 47mn litres of petrol to Texaco's volumes each year.*

The UK Government has given British *Sugar permission to build a 70-MW gas-fired combined heat and power generating station at its factory based at Cantley, near Norwich, in Norfolk.*

Europe

OMV recently opened its first fore- *court in Bulgaria. The company plans to build a total of 75 outlets in the country at a cost of $100mn over five years.*

Hungarian oil and gas company Mol *and Croatian national oil company Ina plan to build a $18mn pipeline to transport Russian and Ukraine natural gas through Hungary to Croatia by 2003. The 50-km pipeline will have the capacity to carry 1.2bn cmly.*

North America

Ultramar Diamond Shamrock (UDS) is *understood to have sold 70 of its US service station outlets to Houston-based USA Express for an undisclosed sum. This brings the number of retail operating units sold in 1999 to 217, for a total of $58.7mn.*

NEWS Downstream

Cooperative LPG road tanker design

Bellamy Engineering of Grimsby in the UK and Lahore, Pakistan-based Descon Engineering have set up a cooperative venture to design, manufacture and market LPG road tankers and large static vessels for the world market.

The venture's first delivery is four 54,500 WC (water capacity) litre propane articulated units to Shell International's Burshane subsidiary. The LPG trailers have been specially designed for difficult road conditions with an emphasis on low centre of gravity and fully secured internal valving.

A range of barrels sizes to all pressure ratings are available from 6- to 25-tonnes carrying capacity. Mounting and fitting out to ASME, ISO 9001 and ADR standards can be carried out in both the UK and Pakistan. Static tanks from 12-tonnes upwards are also available.

Fuel cell refuelling first in California

The California Fuel Cell Partnership – a collaboration between the state of California, energy companies (including Shell Hydrogen) and automobile manufacturers – have unveiled plans to build a new dedicated hydrogen filling station and fuel cell vehicle testing centre in Sacramento, California, by summer 2000.

Shell Hydrogen, along with energy partners Arco and Texaco, will jointly fund the hydrogen fuelling facility which will dispense liquid and compressed hydrogen fuel for the project's 16 fuel cell powered passenger vehicles. The partnership ultimately aims to demonstrate up to 30 passenger cars and 10 buses.

DaimlerChrysler, Ford, Honda and Volkswagen will occupy indoor garage 'bays' designed to house the vehicles for routine servicing, repairs and diagnostic purposes.

'Refuelling is one of the key issues for enabling fuel cell vehicles to reach the mass market,' comments Don Huberts, Chief Executive Officer of Shell Hydrogen. 'The information we and our partners will be able to glean from this Californian filling station will be vital in tackling that issue.'

People who are interested in the project will be able to watch progress at the site as it will be continuously filmed and broadcast on the California Fuel Cell Partnership website which can be viewed at **www.drivingthefuture.org** Public tours of the site will be on offer and information kiosks, graphics and other hands-on learning stations will be incorporated into the interior design.

EC appoints 'super DG'

The merger of the European Commission's Directorate Generals for transport and energy has been announced, creating a new super DG, with 650 staff, writes *Keith Nuthall*. Its Director-General will be François Lamoureux, the current top Commission official for transport.

The new department will forge integrated policies, linking transport and energy issues, and has promised to adopt a balanced approach with regards to renewable and non-renewable energy sources.

LNG first for China

The Chinese authorities are reported to have given final approval for what will be the country's first LNG import project. A new LNG terminal in Shenzhen and a 400 km pipeline are proposed in the southern province of Guangdong. Companies are expected to begin bidding to participate in the \$500mn project shortly. China National Offshore Oil Corporation is understood to be planning to take a 36% stake in the project, with a further 29% to be held by a Chinese consortium. The LNG terminal is due to be completed in 2005.

In Brief

Duke Energy is understood to be com*bining its US natural gas gathering and processing assets with Phillips Petroleum to create a new company – Duke Energy Field Services. The new business, which will operate 67 plants and over 57,000 miles of pipeline, is claimed to be one of the largest natural gas liquids businesses in the country.*

Middle East

Foster Wheeler has been awarded a *contract by Saudi Aramco to develop the Haradh gas programme in Saudi Arabia by the year 2004. The new plant is expected to produce 1.4bn cf/d of gas during its first year of production.*

Russia & Central Asia

State property fund FMN (operated *under the Czech Finance Ministry) is to auction off in April a 70.87% state-held equity in the Paramo refinery of Pardubice, which is primarily a producer of heating oil and asphalt with a base capital of CK1.3bn (\$37mn).*

Lukoil and Mazheikiu Nafta have *announced that they are making progress on a long-term crude supply agreement, reports the United Financial Group's* Russia Morning Comment. *It is understood that Lukoil will be able to use the facilities of the Lithuanian refinery to process up to 30,000 b/d and supply refined products to the Baltic region. In return, Lukoil will sell 100,000 b/d of crude to Mazheikiu Nafta. Lukoil earlier failed to acquire the refinery.*

Legislation granting Gazprom's Blue *Stream pipeline project tax breaks has come into force reports the United Financial Group's* Russia Morning Comment. *It includes a double taxation treaty between Russia and Turkey, as well as a schedule to the 1997 inter-governmental agreement on gas deliveries across the Black Sea which provides relief on VAT assessments based on the value of construction contracts. According to UFG, the eliminated of legal obstacles to the tax breaks will improve Gazprom's chances of completing the subsea pipeline by 2001, well ahead of the competing pipeline being build by Turkmenistan and Azerbaijan.*

Asia-Pacific

SembCorp Industries is reported to be *planning to purchase a further 100mn cf/d of gas from Indonesia's West*

Disappointment at EC block exemption ruling

The UK Petrol Retailers' Association (PRA) has expressed its regret that the European Commission has not acted more radically to ban restrictive and exclusive distribution agreements in the oil sector, when announcing changes to EU competition law last month, reports *Keith Nuthall.*

Competition Commissioner Mario Monti announced on 22 December 1999 that he was to establish a new all-industry 'umbrella exemption' that would allow any company with less than 30% national market share in its sector to strike restrictive distribution deals. It means that the existing block exemption for the oil industry will be scrapped from the end of 2001 – but, because of the 30% rule, this will mean little in practice. At present, only GALP of Portugal, Repsol and Cepsa-Elf in Spain, and BP in Greece are expected to be affected. No oil company in the UK comes anywhere near a 30% share of forecourt trade.

PRA Director Ray Holloway told *Petroleum Review* that he was 'disappointed' with the Commission decision. He called on the UK Government to further liberalise its national regulations, so that oil companies in the UK would have to allow service stations to shop around for fuel. 'It's critical that an inquiry looks at the implication of what the 30% block exemption means here,' he said.

Forecourts alerted to combat crime

Crimes against UK service stations are estimated to cost the oil industry more than £47.2mn every year (approximately £3,200 per service station). West Yorkshire Police, the British Oil Industry Syndicate (BOSS) and Vodafone Paging have launched 'Forecourt Alert' in a bid to combat such crimes.

The system provides a quick and effective way for enabling participating members to exchange vital information regarding an incident, forewarning others of potential problems.

Under the paging Forecourt Alert scheme, staff at the participating service stations throughout Keighley, Bingley and Ilkley in West Yorkshire carry a Vodafone Paging text message pager. If one of the garages experiences a crime related incident – such as a credit card fraud, a motorist who drives off without paying for their fuel or if they experience a robbery or assault – a call is made to a special Forecourt Alert number. Details of the incident are then sent simultaneously to all the pagers carried by members of the scheme. As a result, the whereabouts of the offenders can be monitored and members can coordinate their activity, together with the police, to take action.

West Yorkshire Police, BOSS and Vodafone Paging are also working together to produce a manual for scheme members which details additional measures they can take to combat crime.

Natuna Group in 2004 at a cost of \$100mnly. The company has already contracted to buy 325mn cfld from 2001 at a cost of \$8bnly.

Latin America

The Trinidad and Tobago Government *has given its approval for the addition of two new trains to the Atlantic LNG gas processing facility at Point Fortin, Trinidad. The two trains will have a LNG production capacity of 13bn cmly. The first train is due to be completed in 2002, the second in 2003. The new trains will produce 9bn cmly of LNG, 5bn cm of which will go to supply the Spanish market.*

Africa

The Tanzanian Government *has approved development of the \$343mn Songo-Songo gas and power project nearly half a decade after it had been conceived, reports* Stella Zenkovich. *Tenders are expected to be floated by mid-2000. Gas is to be piped from revitalised wells on/near Songo-Songo Island, off the southern coast, to a 112-MW power plant near Dar-es-Salaam. The plant will be operated by Songaz, a joint venture between Canadian companies Ocelot Energy and TransCanada Pipelines. Funding is being provided by the World Bank and EIB, and equity investment is coming from the IFC and the Commonwealth Development Corporation.*

UK Deliveries into Consumption (tonnes)

Products	†Nov 1998	*Nov 1999	†Jan–Nov 1998	*Jan–Nov 1999	% Change
Naphtha/LDF	267,508	186,442	2,608,377	2,812,543	8
ATF – Kerosene	711,593	722,359	8,349,324	8,803,910	5
Petrol	1,775,008	1,783,134	19,883,709	19,566,169	–2
of which unleaded	1,431,716	1,633,193	15,560,370	16,904,385	9
of which Super unleaded	31,994	59,019	376,363	390,520	4
of which Premium unleaded	1,399,722	1,574,174	15,184,007	16,575,088	9
Lead Replacement Petrol (LRP)	–	–	–	13	–
Burning Oil	342,656	322,120	3,144,896	3,105,717	–1
Automotive Diesel	1,313,095	1,338,385	13,845,006	13,912,448	0
Gas/Diesel Oil	627,293	547,286	6,613,721	6,104,051	–8
Fuel Oil	272,164	193,641	2,548,174	1,900,154	–25
Lubricating Oil	65,164	68,460	754,420	731,746	–3
Other Products	741,080	788,922	7,525,875	7,810,163	4
Total above	6,135,561	5,950,749	65,273,502	64,746,901	–1
Refinery Consumption	499,087	480,701	5,918,944	5,581,852	–6
Total all products	6,634,648	6,431,450	71,192,446	70,328,753	–1

† Revised with adjustments *Preliminary

Facing the future – e-business scenarios

Although the oil industry has been slow to take e-business onboard, new initiatives are gathering pace. *Brian Davies* reports.

Forrester Research predicts that process industries will handle $500bn of trade electrically by 2003. In some segments of the process sector, nearly 10% of the industry's trade could move online. The petrochemicals industry e-business is likely to move quickly from an experimentation phase today towards 'hypergrowth' by 2001. But there are still fears of complacency according to experts at Andersen Consulting. And Arthur D Little offers alternative scenarios for e-commerce uptake which bode ill or fine for the future of some oil majors, depending how fast they take up the challenge.

Kirk Williams, Managing Director of EMEA Operations for e-business and process enterprise optimisation provider Aspentech (**www.aspentech.com**), insists that the introduction of e-business initiatives calls for a major culture shift. 'Oil companies have never really considered themselves as having customers,' he says. 'They believe the business is driven by what margins can be achieved in a commodity market. Now the picture is changing.'

Targeting the supply chain

Aspentech is currently working with BP and Shell to implement e-commerce solutions which will help make customer demand more visible up and down the supply chain, from the service station through to crude oil supplies. This will allow the companies to reduce dependence on the commodity market and increase margins, where currently the least-cost oil producer tends to set the price.

In the oil business, demand is often met by third parties. Williams suggests that e-business offers a global picture of inventory and demand via the Internet. 'There is also a tendency within oil companies to run operations in independent "silos," for exploration and production, manufacturing, supply, refining, marketing and distribution. With the introduction of e-business there is an opportunity to make the extended enterprise transparent inside as well as outside the organisation.'

There will also be a significant impact in terms of trading exchanges and related organisations. Systems for e-business can be implemented throughout the trading cycle: from pricing deals, contractual validation, shipping instructions, insurance and cargo tracking, to reciprocal operations on the receiving end. 'Today most of this is handled by fax, telex and telephone, but all these transactions could be tackled via the Web,' says Williams.

In parallel, there is an opportunity for the provision of enterprise community services. For example, an Internet service could allow regional operations to carry out trial balance on exchange agreements, sharing information by a system which would previously have been too costly on an individual basis.

Andersen Consulting offers some particularly critical comments on the state of e-business in the oil and gas industry. It points out that some companies are already making savings through e-procurement, and claims that 5% price savings can translate into a 5% to 20% increase in operating profits, but many are still dragging their heels. Although some oil companies are developing e-commerce capabilities that will ensure future success, major efforts have primarily been directed at the retail side of the business. Highlighted developments include Mobil's 'Speedpass' in the US, an electronic system which allows drivers to make easy payment at service stations which has gained over 600,000 users to date. Shell is developing a similar product in Europe.

Andersen analysts claim: 'The oil price rebound has alleviated the pressure on national oil companies to fundamentally restructure. The oil majors continue to conduct business as usual and feel insulated by distance from the e-commerce action, which they mistakenly believe is being led by the business-to-retail sector.' As experts regularly point out, business-to-business e-commerce is set to outstrip the glamour and hype of business-to-consumer e-commerce.

There is also the question of attracting new talent. 'As the brightest from engineering and business schools, consultancies and other organisations flock to the e-world, the oil industry must reverse the trend or become a backwater,' says Andersen.

The way forward

Looking to the future, Andersen predicts that broad access to information via the internet will dilute the majors' powers. 'The pace of vertical integration of the oil and gas industry is slowing. That trend will continue because the reasons to integrate – price discrimination, supply security and coordination of activities – will no longer apply as the e-business revolution gathers pace.' Indeed, access to comparative pricing and Internet-enabled coordination throughout the supply chain and beyond, has never been simpler. Finding suitable technology is certainly not the challenge.

Alarmingly, Andersen forecasts that the current status of integrated oil companies faces disintegration. 'Most of the links of the value chain spin off into their own specialities. From exploration to branded retail outlets, the majors' long value chain will give way to the forces of e-commerce and specialisation.' Although the consultancy suggests that alliances will thrive for large projects which require greater risk sharing, 'the Exxon Mobils and BP Amocos of the future will not be huge conglomerates. Rather, they will be highly focused management companies leveraging industry knowledge to create alliances, managing contractors and trading in oil and gas.'

The virtual oil company

Neil Thomas of Arthur D Little's Energy Practice takes up the debate here. Apparently, five years ago Arthur D Little proposed the idea of the 'The Virtual Oil Company', but met critical disbelief. In essence, the downstream Virtual Oil Company was seen as a knowledge-based enterprise founded on an intimate knowledge of its customers and delivering growth through building brand value. 'Virtual companies do not have to be part of either the production process or the traditional distribution process. They exist through their ability to control flows of information to the customer,' says Thomas.

At the time, many of these ideas were seen as radical and in some cases technically infeasible. Thomas insists: 'That is no longer the case in today's world of e-business. The open, interactive infrastructure of the Internet provides the glue to hold the virtual oil company together.' In fact, the domain name e-Energy has been registered, but Thomas asks: 'Who will have the vision to take the concept to its full potential?'

Current applications

Many oil companies already apply tools of e-business directly to their core product/service supply chain. BP Amoco has started using the Internet to purchase basic catalogue items. These represent only 15% of its $20bn annual procurement budget, but 50% of all transactions, and it has targeted $200mn savings annually from these items alone. By the end of 2000, BP Amoco aims to conduct 95% of all purchases electronically.

Several oil companies, including Chevron, have set up extranets for two-way transfer of information within their network of retail service stations. BP Amoco has also mooted potential cost savings of 1000%, by moving traditional visits by company sales representatives to direct customer ordering via the Internet. Research suggests that the cost of a transaction using a field sales executive can be slashed from $500 per transaction to merely $10 using the Internet.

Reshaping the future

Thomas claims that the impact of e-business will go far beyond improving the efficiency of key business processes. 'It has the potential to reshape the entire structure of the downstream industry.' He offers two scenarios for the oil and gas industry in the year 2010.

In the first, he forecasts the implications if the majors fail to rise to the challenge presented by e-business. With primary focus set on reducing costs via the improved efficiencies of e-technologies, there are likely to be not insignificant savings, 'but fundamentally the business model will be the same as it has been for the previous quarter century. The industry will remain integrated, with production-led organisations.' Meanwhile, in the e-business world, simply satisfying customers, which was formerly a basis for differentiation, will become a threshold criterion expected by all customers and delivered by all credible vendors.

Thomas warns, 'While the oil companies merely set their sights on conducting business in better ways, others will conduct the business in radically different ways, with new business models. New intermediaries offering enhanced customer value proposition will reconfigure many of the channels to market.'

For example, in the retail sector he suggests that the supermarkets will link with major motor manufacturers to provide total motoring solutions to the most attractive segments identified by their extensive customer databases. As part of the hassle-free offering, motorists will no longer have to shop around for the best value fuel. In-car internet technologies will provide GPS directions to the nearest service station, with continuously updated information on fuel prices. Customer's search costs will be minimised, and oil companies' profits on retail fuel sales will vanish. Meanwhile, supermarkets will maintain customer loyalty by offering reward points on all transactions on their in-house credit cards.

In this scenario, oil companies will continue to offer a standard offering across all their service stations, effectively catering to the lowest common denominator. Thomas warns, 'Their belief that the convenience of their network of stations is unassailable will be shattered by the increasingly sophisticated supermarket home delivery services.'

In the commercial fuel markets new 'infomediaries' will be set up between customers and oil product suppliers. Their primary role will be to provide comprehensive customer service solutions that include guaranteed lowest prices on fuel, but never take title on the product. Fuel storage tanks at factories and transport depots, equipped with intelligent replenishment sensors, will be linked via the internet directly to these new agents who pool all their customers' requirements together and seek automated bids from fuel suppliers. Similarly, agents will coordinate the fuel requirements of the major shipping companies. 'By pooling demand, online agents will be able to lower prices to customers while enhancing service at minimal additional cost,' says Thomas.

'By 2010, large parts of the value chain will have been captured by new players. Oil companies will have become primarily suppliers and shippers of commodity products. Their strategy of cautious incrementalism will result in the continuation of the inexorable trend towards commoditisation that we witness today.'

More optimistically, in the second scenario, the leading lights in the

The IBM experience

IBM now sees itself as an e-business solution provider, working closely with major ERP system providers to offer fully integrated systems in refinery, chemical and petrochemical companies. With Mobil, IBM has developed a system called "Bestnet" for sharing best practice for maintenance in refining operations worldwide. In Denmark, IBM has created a web-enabled order fulfilment system for lubricants and heating oil customers of Hydro-Texaco, a joint venture between Norsk Hydro and Texaco. The customers can even plan their orders via the Web according to predicted weather conditions. In France, an online service has recently been created to handle pump maintenance at 1,500 service stations throughout the country. The intranet application runs on Lotus Domino, so managers at service stations nationwide can log maintenance requests and track progress.

According to Bill Payne, Managing Principal of IBM oil and chemicals and petroleum e-business development in the EMEA: 'Each organisation needs to develop an e-vision with a short- and long-term strategy. This can be fairly straightforward if supported from the top, but there has to be a clear vision which is rolled out in short-term manageable projects, with an eye on quick wins and a longer term infrastructure. However, some companies will bypass this process by creating entirely new web-based business models. Unfortunately, most major companies are trapped by the culture and thinking of a bygone era.'

Payne suggests that organisations must ask the following questions:

- Regarding competition: Which of your current competitors are most advanced in their e-business thinking and implementation? Why? Have you built an e-business competitive scenario? If not, why not? Who are your emerging electronic competitors?
- Regarding customers: What would you do if your top three customers demanded you deal with them electronically in order to continue to do business with them? What is your communications strategy with your customers? How much is currently or planned to be electronic? How much business do you transact over the Internet, and how much in 12 months' time? How are you using the Internet to enhance your products and services and add more value to customers?
- As a company: Do you know the top five opportunities to save money in your organisation by implementing an e-based system? How are you using e-business to leverage knowledge and communication within your business? What are your current e-business initiatives? How much are you spending and what is the return?

industry will recognise the potential offered by e-business to change the industry structure fundamentally. They will identify the key control points in the value chain quickly and increasingly shift to the final customer interface. 'As a result they will re-segment downstream oil businesses around four global segments: manufacturing, distribution, midstream marketing and retail merchandising, each enabled by different aspects of e-business,' says Thomas.

In this scenario, he sees manufacturing being consolidated into a smaller number of large-scale, highly efficient integrated oil, gas and chemical complexes. These will often be owned by multiple partners and serve a wide ranging customer base comprised of formerly competing integrated oil majors. Procurement of feedstocks and maintenance materials will be automatically handled by e-commerce systems, with the Internet providing a platform for global knowledge sharing of best practices with affiliated manufacturing complexes, suppliers and customers to optimise efficiency.

Product distribution will be handled by dedicated, scale-driven product movers. One-stop storage and distribution providers will leverage e-business across the entire breadth of their operations to optimise costs and efficiency.

Midstream marketing companies will focus on providing multiple energy products and services to large volume energy consumers, offering 'total energy management solutions' to customers, not just oil products. 'By aggregating their customers' demand, they will be able to access the most cost efficient sources of electric, gas and oil products. Total e-business automation of supply chain transactions, scheduling, risk management and ancillary support processes will ensure the lowest cost to the market and a highly developed customer intimacy business model,' says Thomas.

In retail merchandising, branding is king. 'The oil companies will have to shift from their focus on selling oil products and look instead to leverage their brand,' says Thomas. Though supplying fuel to motorists remains a core part of the offering, it will no longer be viewed as their sole raison d'etre. E-business offers far greater insight into customer requirements. To succeed, companies will have to be far more sophisticated in their customer segmentation analysis, tailoring the offering at service stations to match customer requirements.

Keys to success

'To stave off the threat posed by home delivery shopping services from major supermarkets, service stations will have to act as local collection/delivery points and increasingly focus on their key advantages of speed and convenience,' argues Thomas. With a global brand as a hub to which numerous products and services are offered to customers, oil companies will need to form alliances with major vehicle retailers and manufacturers, providers of repair, maintenance and car care services, banks, finance companies and even major supermarkets. These alliances will be bound together by e-business systems into a virtual company of impressive scale and scope. In the world of e-commerce, the potential for merchandising is only limited by the value generating market e-commerce companies chose to capture.

In a brave new e-world, simple optimisation and enhancement of existing systems is not enough. Only a radical fresh business model will succeed. Looking at the speed of e-business development, we probably face this scenario within a couple of years, rather than a decade.

E–business procurement

Shell venture targets global Internet market

Shell and Commerce One, a provider of global business-to-business e-commerce solutions, have unveiled plans to form a joint venture to develop an Internet market place for procurement of a whole range of supplies and services in the oil, gas and chemicals industry. Shell anticipates that the new system will 'significantly' cut procurement cost.

The aim of the new joint venture is to establish an electronic exchange to link buyers and sellers of goods and services across the energy industry, throughout the world. The new global exchange, which will be based on Commerce One's (visit **www.commerceone.com** or **www.marketsite.net**). The MarketSite portal, will be designed to be open to energy companies, their suppliers and their customers. It will also help regionally based small and medium sized companies to compete globally in a way that was not possible before, state the two parties.

As part of the agreement, it is anticipated that Commerce One will be paid license fees for its Internet technology. Initially, Shell will hold the majority stake in the new venture. Commerce One and the joint venture staff will also have an equity stake. In addition, it is expected that Commerce One will grant Shell warrants to receive 4.3mn shares of Commerce One common stock (currently valued at $730mn) in exchange for the right to receive shares in the new company prior to its initial public offering. The exchange of Commerce One and joint venture options is contingent upon certain events, including a listed initial public offering (IPO) by the new company at a certain pre-determined minimum value.

Shell expects the new system to cut its current $29bn procurement budget significantly, leading to lower capital expenditure as well as cost improvements which are part of the $4bn target announced by the group in December 1999.

Commenting on the deal, Harry Roels, a Group Managing Director of the Royal Dutch/Shell Group of companies, said: 'This is a very significant move for us. Not only does it build on the changes we have been pushing through in procurement, but by allying with the dynamic Commerce One company we are setting the pace in the energy industry in terms of how we exploit Internet technology'.

'The new exchange is intended as an open gateway and we welcome other energy companies to join in. There are huge efficiencies to be gained by everyone, and the more members we get, the more successful it will be.'

The market is planned to 'go live' in the 2Q2000.

The perfect IT system

As part of its ongoing e-commerce and e-business theme, *Petroleum Review* searches for the perfect oil and gas IT system. *Gordon Cope* reports.

It is Monday morning and the Board of Directors is calling for more profits...Now. With a flick of a mouse you call up sales at the forecourt and note with satisfaction that volumes for the weekend are up. It is time to bring more production onstream.

Unfortunately, when you check with production, you discover that your oil field is at maximum production.

Not to worry; the pull-down display of exploration seismic shows that there is an excellent prospect adjacent to your producing field, and a split-screen chart indicates that a semi-submersible rig is available this month to drill it. A quick e-mail to the refinery confirms that periodic maintenance is complete; all that is necessary now is to inform the Board that more profits are on the way – and confirm your golf foursome for that afternoon.

As described above, the perfect oil and gas IT system not only places real-time information about all assets – ranging from exploration, production and rigs through to refineries and petrol pumps – at the fingertips of management, but also allows executives to react instantly to the changing business environment to maximise profit and efficiency. But is such a system feasible?

Some companies do have 'em

Imperial Oil Ltd (**www.imperialoil.com**) is a major Canadian integrated petroleum company. With four refineries across Canada, Imperial converts 430,000 b/d of crude into hundreds of petroleum products and fuels. 'Our products are demand-driven, and demand changes seasonally and daily,' says Bruce Orr, a Senior Manager with Imperial. 'We have to react quickly.'

Imperial first installed automated, electric-information systems downstream 25 years ago. 'We now have 10,000 sensors hard-wired at four refinery sites,' says Orr. 'The information is used in a very fast loop control to automatically maximise production and efficiency.'

When point-of-sale information indicates local demand, Imperial can automatically deliver product through several thousand kilometres of pipeline. 'We have remote-control of pipeline systems,' says Orr. 'All information is linked by real-time live systems. We blend directly into our pipe.'

Nor is Imperial's system restricted to downstream – a host of upstream applications, from seismic records to rig utilisation, is tied in. 'We have 400 to 500 applications in total,' says Pierre Côté, Manager of Information Applications at Imperial. 'We have multiple systems and applications, and an enterprise-wide system, SAP, for our transactions and financial [analysis]. For instance, we have an application that measures tank levels in refineries, then that information is pooled and bridged to SAP (www.mysap.com). We then have an executive information system that is a key-performance indicator.'

Such a comprehensive system, however, does not come cheap. 'The total cost of personal computers, LAN [local area network], mainframe and controls was in the C$1bn range,' says Côté. 'Maintenance and operating costs annually run at 10%–15% – around C$150mn/y.'

Starting from scratch

If that sounds a bit rich for your blood, fear not – one can still have a valuable, real-time IT system for far less.

'Building an IT system [like Imperial's] today would cost a fraction of what it cost 10 years ago,' says Jacob Stein, Senior Strategic Planning Director for Sybase, a California-based data management company (**www.sybase.com**). 'It would be cheaper by a factor of ten to hundred times; a $1bn system built a decade ago could be built today for between $10mn and $100mn.'

Savings in hardware and communications play a dramatic role in reducing costs. 'Reliable networks were terribly expensive,' says Stein. 'Now, even home users can get a dedicated digital subscriber line for under $50/month. And the functionality of a personal computer that cost $3,000 a decade ago can now be had for a few hundred dollars.'

But, most significantly, oil companies need no longer develop the necessary software applications in-house from the ground up – boutique software firms have coded a myriad of specialty applications specifically for the petroleum industry. 'As a result, software costs are way down, and you are starting at a much higher level of functionality,' says Stein.

Exploration

Houston-based Landmark Graphics (**www.lgc.com**) is one of a few companies to offer a complete upstream package allowing geoscientists to analyse and integrate their entire data base of seismic and geology in real-time.

With a starting price of $50,000, Landmark's software package employs some of the most sophisticated interpretation and display modules in the sector. Using a desktop workstation, explorers can gather, interpret and present the latest, up-to-the-minute information. Exploration plays (such as land sales) that formerly took a team of geoscientists a week to whip up can now be done by one professional in half a day.

But the real advantages of such a system lie in the areas of multi-disciplinary collaboration and visualisation. 'This system is excellent for exploration and development of complex structural and stratigraphic plays, like the type you see on the East Coast,' says Doris Ross, a Senior Technical Consultant for Landmark. 'Everyone can participate; geophysicists, geologists and engineers.'

Presenting an exploration play on paper charts and graphics has also gone the way of the rotary-dial phone. The latest rage is the 'cave', a room fitted with wrap-around screens and 3D projectors (for a mere $1mn) that allow up to 30 boffins to literally walk into a potential reservoir and play about.

Gulf Canada Resources uses Landmark's package for most of its exploration work, and is quite pleased with the results. 'I recommend the system to other companies because it reduces uncertainty,' says John Van Der Laan, a Gulf Geologist. 'You reduce risk by eliminating bad wells.'

Drilling

Once an exploration play has been delineated, it is up to the engineer to drill it. No longer do roughnecks rely on spanners to toil for black gold; the preferred tool these days is the laptop computer. 'Let's say you're casing an offshore well and you have to re-design the casing due to unforeseen circumstances,' says Dr Jonathan Lewis, Landmark's Vice President of Information and Business Management. 'It usually involves a flurry of faxes back and forth as you check inventory and costing – it's highly inefficient.'

Landmark has recently re-written its StressCheck application (a technical software programme that allows engineers to design casing) to tie into SAP's inventory and accounting systems. 'It allows you to pull up inventory and costing in real time,' says Lewis. 'It can reduce cycle time from weeks to minutes.'

Production

'Upstream oil companies don't compete on quality,' says George Quesada, Director of Product Development and Support for PanCanadian Petroleum. 'Competition is restricted to producing fast and efficiently. Automation can help.' PanCanadian has over 4,000 wells in production, primarily in the western Canada basin. Back in 1993, the company employed an array of field operators to visit each well daily. 'When an engineer had to drive to a field every day, they were not doing engineering work, they were doing driving,' says Quesada. 'It was very inefficient.'

PanCanadian then decided to spend C$35mn over seven years to design and install an automated system (**www.pantechsolutions.com**). The basic installation is the remote terminal unit, or RTU, that measures a well's pressure, temperature and flow once per minute and sends the data back to one of several production centres, where performance is automatically optimised. Operators now also know instantly when a well is beginning to malfunction, and can dispatch a crew to deal with a problem before it happens.

The benefits to PanCanadian include less downtime and lower operating costs. 'In 1993, we had one operator to 20 wells,' says Quesada. 'Now, we have one operator per 70 wells. 'Savings range from 2–10% of operating costs, depending on the field.'

Financial information

The value of knowing precisely how much oil and gas is being produced at any given moment goes far beyond savings in production costs.

For the last seven years, Ocean Energy Resources (**www.oceanenergy.com**) has been virtually doubling in size through acquisitions and mergers. By 1998, it had production in Equatorial Guinea, Côté d'Ivoire, Egypt, Russia and the Gulf of Mexico. Looking after 4,000 production wells scattered around the world was, to put it mildly, a headache. Not only that, but trying to pull together disparate data each year for the annual budget projections was eating up valuable engineering resources.

In 1997, Ocean contracted with Merak Projects (**www.merak.com**), a software firm that specialises in petroleum economic analysis, to install their 'Living Business Plan'. 'A Living Business Plan is a best-practices planning tool that routinely updates and manages information, allowing Ocean to react quickly to changes in their portfolio and the industry,' says James Henry, Merak's Manager of Value Development.

Merak uses several integrated applications to pump data through Ocean. One cornerstone application for the 'Living Business Plan' is 'Peep', the Petroleum Economics Evaluation Program, that allows engineers to do economic and decline analyses. Another Merak application, 'PetroDesk', visualises the entire operation for management. 'It will map pipelines, well productions, land and all sorts of facilities,' says Henry. 'PetroDesk's open system can map various data sources together, and graph and report the results for total asset management.'

For an oil company with an annual E&P budget of £250mn, the 'Living Business Plan' system can be installed for 0.1% to 0.5% (£250,000 to £1.5mn). The system's hardware requirements include a central server and minimum Pentium 300 desktop computer for each user.

While the software itself takes only one month to install, integrating all of the affected departments within a company can take up to one year. 'Implementing the Living Business Plan process at a company requires a change in corporate philosophy,' says Henry.

For mid-level managers at Ocean, the system has been a boon. 'By having a 'Living Business Plan', we can grab the entire portfolio and run the entire 2000 budget, or the next quarter,' says Mark Furber, an International Resources and Planning Engineer for Ocean. 'Before, my time was split 50:50 between finding prospects and budgets. Now, it's only 15% on budgets.'

Bringing it all together

One of the keys to building an off-the-shelf, real-time system is using applications that can interact seamlessly with one another. 'The oil and gas industry has a myriad of programmes that allow real-time information, but they don't often talk to one another,' says Brad Phillips, a Senior Director for XWAVE Solutions (**www.xwavesolutions.com**), a network consultancy. 'Building applications is no longer key, but integration is.'

XML, or extensible markup language, is being developed as a non-proprietary standard to aid integration. 'XML allows applications to talk to one another,' says Phillips. 'It allows the Internet to be used to pass information back and forth.'

BizTech for Energy is another standards initiative. It integrates technology-to-business (T2B). It will tie geology, geophysics and drilling to business systems like SAP.

Advantages

Those who have experienced real-time systems agree that they perform a valuable service. 'All the information is at your fingertips,' says Ocean's Furber. 'It allows you to maximise the potential of a field.'

And, many experts in the field predict substantial cost savings. 'Look at the cars that were being manufactured in Detroit 40 years ago,' says Landmark's Lewis. 'You had poor fuel economy and high emissions. Now, you see cars with excellent mileage and low emissions. That's because the engine is highly integrated with a suite of IT components that monitor air temperature, road conditions and a host of other factors to optimise performance.'

'It's the same with the oil and gas industry,' says Lewis. 'When you go from a dis-aggregated to integrated, you'll get another phase of productivity gains in the neighbourhood of 2%. Oil companies spend $35bn annually on drilling wells. A 2% saving is $700mn.'

Drawbacks

One of the biggest drawbacks to integrating systems is not hardware or software, but personnel. 'You can hardwire land data into financial accounting, but the landmen don't want financial to manipulate their data,' says Bev Draper of XWAVE Solutions. 'When it comes to an integrated system, getting buy-in (bilateral acceptance) is a huge issue. You must set up protocols and security and access. It's a very complicated process.'

A system that is over-designed can also quickly become a dinosaur. 'To have a totally-integrated, monolithic solution might take a lot more than 10 years to develop, and 10 years is a lifetime in the information business,' says Imperial's Côté.

Thirdly, and perhaps most importantly, even the best-designed computer system can misbehave. 'The more authority you give a system, the more interesting the failures become,' says Jacob Stein of Sybase. 'Complex systems can fail in complex ways.'

Looking to the future

Regardless of the challenges inherent in creating the perfect real-time system, it would be fare worse to ignore its potential. 'While software can't predict the future, it can help build flexible, data-rich 'what if' scenarios that will allow companies to react quickly to market changes and rapidly evaluate new business opportunities,' notes Jeremy Walker, UK Sales and Marketing Director for Merak. 'Without flexible tools that keep pace with the rate of industry change, companies may never know what opportunities they are missing, or what disasters they could have avoided.'

Shifting to the seabed

Economic pressures to enhance oil recovery and drive down development costs are leading to subsea technology innovations which could ultimately result in the disappearance of offshore platforms. *Terry Knott* reports.

Figure 1: The world's first subsea separation and injection system, Subsis, will soon be operating in Norsk Hydro's Troll field

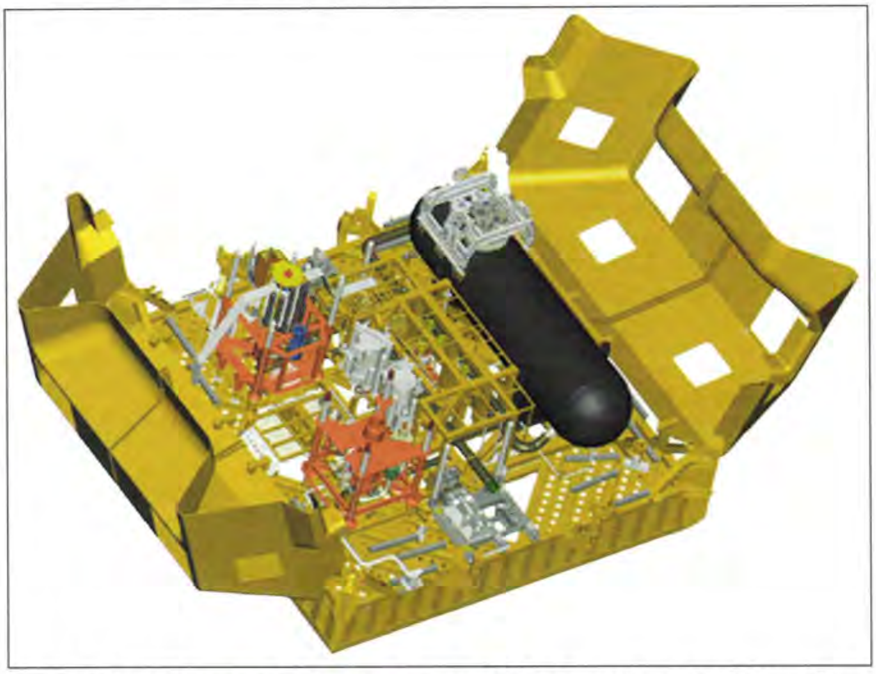


Figure 2: Subsis is capable of handling some 63,000 b/d liquids and 800,000 cm/d gas

Sitting on the Norwegian seabed in 350 metres of water, a pioneering milestone in underwater technology is quietly waiting for its grand debut. In a few months' time the world's first subsea separation and injection system – Subsis – is scheduled to come into operation in Norsk Hydro's Troll C field, promising to revolutionise the face of offshore oil and gas developments.

If Subsis proves a success it will represent a major step in the industry's drive to move offshore processing operations from the familiar territory of fixed and floating platforms to the seabed, a move which holds attractions for both mature fields and new developments, particularly those in deepwater regions of the world.

By separating wellhead fluids – oil, gas and produced water – at or near the subsea well on the seabed, at the same time reinjecting unwanted large volumes of water back into the reservoir or treating this for discharge to the sea, the very significant economic benefit of eliminating pipeline and surface facilities may be realised. Removing produced water at the wellhead (in older fields this can account for 90% or more of overall fluids) means transporting less volume to the surface facilities, drastically reducing the size and costs of new pipelines and topsides equipment on platforms or floaters, or freeing up existing capacity to handle more hydrocarbons from marginal satellite fields. Of equal importance, taking the water out reduces back pressure on the well, leading to increased oil and gas recovery in the order of 3% to 6%.

Pilot project

The development of Subsis was launched four years ago by ABB Offshore Systems in Norway. Identified as a 'high impact project' with a $10mn development budget, Subsis required expertise from across the giant ABB engineering group in conjunction with leading subsea pump specialist Framo Engineering. Eighteen months later, Norsk Hydro ordered the first system to act as a pilot on its new Troll C development under a $25mn contract, which could lead to six more units being integrated into the 50-well subsea development.

Subsis consists of a structural steel frame supporting a set of modular components, designed to be maintainable through diverless intervention using remotely operated vehicles, and retrievable from the surface if necessary. The frame, fitted with two hinged GRP covers to protect the equipment, is located on the seabed by skirt piles and further fixed in place by the water injection well below.

Wellhead fluids from eight subsea wells will enter the unit via a single 10-inch diameter flowline, with oil, gas and water being separated in a purpose-designed, 9-metre long, three-phase gravity separator which is also capable of removing sand from the fluids. A 1.8-MW electrically driven subsea pump – claimed to be a 'breakthrough technology' by supplier Framo Engineering – will reinject the separated produced water into the water injection well through a subsea tree housed within the unit, while oil and gas will exit the system as separate streams to be combined into a single flowline for transfer to the Troll C floating platform located 4 km away.

The Subsis unit, measuring some 16 metres by 16 metres and 6 metres high, weighs about 390 tonnes in air, and is capable of handling some 63,000 b/d of liquids as well as 800,000 cm/d of gas. Although, the Troll C field came onstream in November 1999, the Subsis pilot is currently being bypassed as planned, awaiting completion of the water injection well.

A single subsea umbilical running from the platform to the unit will supply electrical power through a 6.6-kV cable to operate the pump and for control and instrumentation, and will deliver any chemicals which may be required. The step-out distance for Subsis units from a host platform is up to around 10 km, dictated by the alternating current power line. However, this is expected to jump to 60 km with ABB's ongoing development of Sepdis – subsea electrical power distribution system – targeted at feeding several Subsis and other subsea systems from a single subsea power centre supplied by a 36-kV cable from a platform or onshore.

Technology gaps

During the development of Subsis, ABB identified a number of 'technology gaps' which had to be filled if the concept was to become a reality. In addition to incorporating the pump, marinisation for 350 metres of water, modularisation and diverless maintenance, a number of prototypes had to be developed, notably for the gravity separator and inlet design, fluid level monitors to control the separation process, and a wet mateable electrical connector, known as Mecon. The latter scooped a top engineering prize in its own right at last year's Offshore Technology Conference in Houston, Texas, and is also a key component in the Sepdis design.

Economic prize

While the technology challenges remain significant, the eyes of the operating oil companies have stayed firmly on the economic prize which Subsis could deliver. According to ABB, the conventional route for adding a 120,000 b/d, 10-well satellite field to an existing development 20 km distant, with four injection wells and a 10-inch pipeline tieback to the platform, could cost \$100–\$150mn, including topsides equipment modification and expansion. Subsis would come in around half this, while the expected 3%–6% increase in oil recovery would raise net present value of the development by \$160–\$320mn.

In addition to capex considerations, the fact that produced water is reinjected rather than treated for discharge, offers further benefits. ABB points to predictions that produced water on the Norwegian continental shelf alone has been estimated to treble from around 40mn t/y in 1996 to 120mn t/y in 2000. With possible legislation on the cards for discharge levels of oil in treated produced water to be cut to zero, subsea reinjection could offer a very attractive alternative.

Next generation systems

Although ABB appears currently to hold pole position in the subsea processing race, there is no shortage of competitors offering 'next generation' designs for separation and injection systems, among them leading contractors Aker Maritime, Doris Engineering and Kvaerner. The associated challenge of distributing high voltage power on the seabed has also attracted big names into the arena, including Siemens and Alcatel Alsthom, with strategic alliances being formed among the key players.

Kvaerner's oil and gas product companies are cooperating closely in the development of 'standard' subsea process systems based on gravity separation, and are also moving ahead with a compact series of modularised designs, employing some of the emerging process technologies originally conceived for topsides applications.

Among these are cyclonic gas/liquid separators for bulk separation and gas scrubbing, liquid/liquid separators and pre-separators, solid/liquid separators and handling systems, and a compact electrostatic coalescer. The latter could provide benefits subsea in cases where improved water removal from the hydrocarbons stream could eliminate costly chemical additive systems normally required for hydrate inhibition. Following conventional three-phase separation, the oil stream containing around 10–20% residual water would pass through the compact electrostatic coalescer to induce water droplet growth. The stream would then be processed in a compact liquid/liquid separator aimed at removing water down to less than 0.5%.

Kvaerner's compact coalescer under test

Going downhole

But as promising as these and other innovations appear, the industry's shift underwater is not stopping at the surface of the seabed. Several companies are already investigating the practicalities of separating produced fluids in the wellbore, with unwanted produced

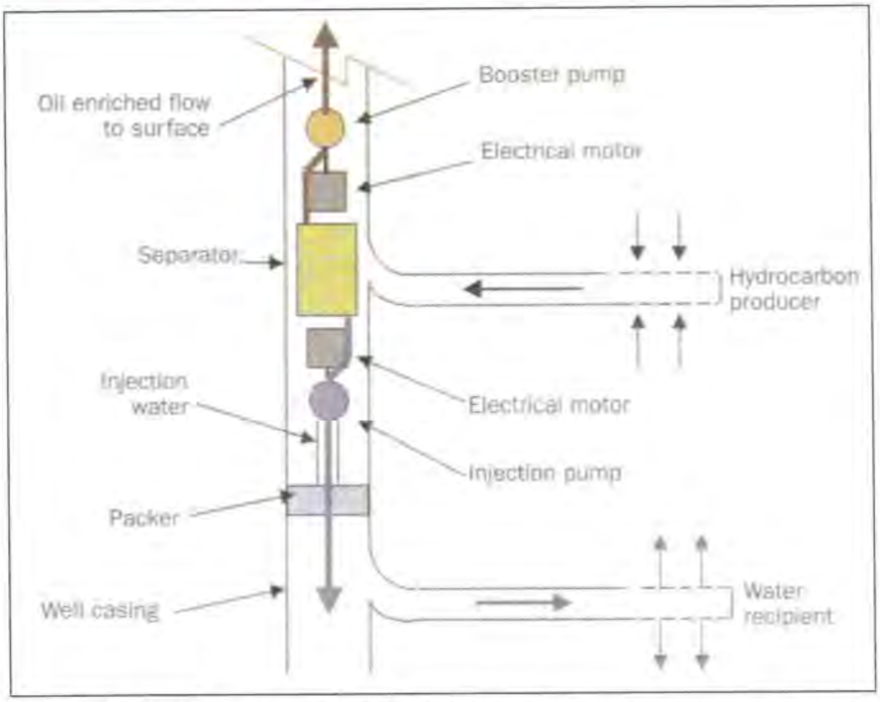


Figure 3: Full-scale prototype downhole separation and injection systems have been tested in Texas

water being reinjected at source.

According to Kvaerner, downhole oil/water separation (DOWS) offers potentially large capex savings – a system may cost only one-sixth of a seabed alternative – and greater separation efficiency. Tests indicate that at the higher pressures and temperatures existing in the wellbore, the separation process can occur over 20 times faster than on a platform, and as water is removed from fluids moving to the surface, flowing friction is also reduced, allowing oil higher production rates from the reservoir.

However, downhole also means some downsides. Traditional electric submersible pumps (ESPs) used for a number of years in onshore wells to reinject water into the reservoir have shown up problems in power transfer, seals, bearings and contamination of the motor housing, says the company. Locating equipment in the wellbore also reduces well access for workover operations.

Despite these drawbacks, Kvaerner believes it has a leading edge in downhole oil/water separation following involvement in a joint industry project with ESP manufacturer Reda, backed by ten oil companies. With the objective of determining the feasibility of a DOWS system to handle 20,000 b/d with high water cuts, Kvaerner Oilfield Products (KOP) in Norway built a full-scale prototype system which has undergone testing onshore at Texaco's Humble test well near Houston, Texas.

The unit is a dual stage device consisting of two banks of hydrocyclone separators and two variable speed drive ESPs (see **Figure 3**). Hydrocarbons enter the wellbore and pass into the first bank of oil-water cyclone separators to remove the bulk of the water, which is then further treated by de-oiling cyclones for cleanup. An ESP below the separators reinjects the water into a lower zone of the reservoir, while the separated oil is pumped to the surface by the other ESP, located above the separator bank. According to KOP, tests at Humble on real offshore crude were successful in removing 85–90% of the total water flow and maintained water quality around 300–400ppm, acceptable for reinjection. An alternative DOWS unit, built by Baker Hughes, showed comparative performance in the Humble trials.

The cyclones are manifolded together and housed in a 9 $^{5}/_{8}$-inch diameter casing to fit into the wellbore, the separator measuring 24 metres in length, while together with the ESPs, the whole unit approaches some 80 metres.

Gravity separation system

Hydrocyclones and ESPs may soon be upstaged by what is claimed to be the first downhole gravity separation system, referred to as H-SEP. Working together, the Weir Group of Glasgow, KOP and Norsk Hydro have recently successfully tested a prototype H-SEP at the oil company's Porsgrunn R&D facility south of Oslo, Norway.

At the heart of the system is Weir's hydraulic submersible pump (HSP) which was originally developed with support from Texaco, the UK Department of Energy and Scottish Enterprise, a gas handling version of which was recently ordered for Texaco's Captain field in the North Sea. For H-SEP, the HSP is combined with a horizontal gravity separator, patented by Norsk Hydro and manufactured by KOP. Using crude oil taken from the Njord field, H-SEP obtained export quality oil containing less than 0.5% water, while producing injection standard produced water containing leas than 500ppm of oil, says Weir, and can operate at water-cuts ranging from zero to 100%.

The process is made possible by the separated water being reinjected above the fracture pressure in the waste zone, using the HSP. In normal operation the system would be installed in a well from day one of the field's development and is designed to eliminate the high maintenance costs associated with cyclone-based downhole separation systems, which have had limited market acceptance and are more appropriate for high water cut applications.

'With the same well being an oil producer and a water injector, the potential saving is equivalent to the cost of an entire new well or topside processing facilities,' explains Bjarne Olsen, General Manager of Weir Norge. 'Fluid separation takes a fraction of the time using the H-SEP system compared to that taken topside, and the technology is simple, robust and cost effective. It has rewritten the rules for producing oil from subsea wells and is a major step forward for oil companies wanting a full subsea development.'

EU seeks mirage of energy security

Faced with the EU's growing reliance on imports of natural gas, the European Commission has issued an analysis of the complex issues as a Communication under the title of *Security of Natural Gas Supply*. The analysis in itself can hardly be faulted, but its conclusions, inevitably, can only be described as 'making the best of it'. *Fred Thackeray* reports.

The Energy Directorate has been pre-occupied latterly with the EU's Kyoto commitments and at the same time with pushing forward the liberalisation of the electricity and gas markets. The Communication it has now issued on supply security represents, it says, 'the Commission's response to the May 1996 Energy Council's call for an in-depth examination of EU gas security.'

It is expected, according to the latest estimates, that the EU's gas import dependence will increase from about 40% today, to 52% by 2010, and 67% by 2020. One may add to this summary for the EU as a whole that as much as 51% of the EU's indigenous production in 2010 is estimated to be from UK fields. By that year, the UK is estimated to be a small net importer of gas, after consuming all its own production. If we take the statistics leaving out the UK, import dependence for the rest of the EU will already be almost 73% by 2010.

These predictions are taken from estimates in another analysis* also published by the Commission in December 1999. This provides baseline figures for the EU's demand and supply of all forms of commercial energy up to 2020. As shown in the accompanying table, however, the sharp increase in gas import dependence is associated with only very modest rates of growth in gas consumption – at an average of 1.7%/y in the period 2000–2010 and only 0.7%/y in 2010–2020.

The significance of these estimates is enhanced by the fact that the December report is based on extensive discussions with energy experts and organisations throughout the EU. It explicitly claims to reflect the expected outcome of energy policies at present in force in the member countries, if there are no new climate change initiatives. One important consequence, it anticipates, is that on this basis the EU will fail to meet its commitment to reduce CO_2 emissions by about 8% by 2010, and will instead increase them by about 7%.

Faster than expected growth

The Communication on supply security suggests that the growth of gas demand might be faster than the baseline estimates, taking into account 'the latest and progressively competitive technological developments of micro gas turbines for heat and power produced in individual dwellings.' It adds that natural gas based fuel cells in the power and transport sectors may also increase natural gas demand. Further, it says, in the longer term the uncertain future of nuclear power in certain EU countries could also affect gas demand.

If growth of consumption is faster, so will the growth of imports be and so will the increase in import dependence. Faster growth and higher import dependence than estimated in the new EU reports in fact appears probable. An important indication is provided by the expectations of major players in the European gas industry, as implied by the contracts they have made for imports. According to the EU Communication net contracted gas imports for 2010 total 198mn toe (213bn cm). But the writer's own estimates, based on collating published information, put the total 20% higher, at 257bn cm. Even at this higher figure it is estimated that there will be demand for additional imports as yet uncontracted in regard to meeting a forecast demand of 533bn cm. If this occurs, natural gas import dependency will already be 69% by 2010 for the EU as a whole.

The point is highlighted in the new Communication on supply security that increasing reliance on natural gas in itself constitutes an improvement in security, since it increases the overall diversity of all forms of energy supply. Gas supply security is supported also, the analysis says, by the fact that natural gas production within the EU is made by a large number of companies – it mentions that in 1996, 33 companies produced 94% of the total. Again, however, it is pertinent that a high proportion of this number was in fields in the UK sector of the North Sea and in the Netherlands. Thus, in 1998, the number of companies sharing in UK production totalled no less than 48; and license holders in the Netherlands totalled 11. 'Similar situations already apply to various degrees,' the Communication claims, 'to the external gas producing countries and are expected to further develop.'

Import dependency for natural gas supplies will, of course, be increased as

	2000	2010	2020	% changes 2000–2010	2010–2020
Indigenous production (mn toe)	783.3	721.8	610.7	(7.9)	(15.4)
Coal and other solids	110.3	85.9	70.3	(22.1)	(18.2)
Oil	165.4	129.6	101.0	(21.6)	(22.1)
Natural gas	204.4	191.0	141.0	(6.6)	(26.2)
Nuclear	223.1	227.1	198.6	1.8	(12.5)
Hydro, biomass and renewables	79.1	88.3	99.9	11.6	13.1
Net imports (mn toe)	711.0	881.8	1,057.0	24.0	19.9
Coal	96.7	96.1	148.0	(0.6)	54.0
Oil	479.8	573.3	616.8	19.5	7.6
Natural gas	133.4	210.2	289.6	57.6	37.8
Electricity	1.2	2.2	2.5	83.3	13.6
Inland consumption (mn toe)	1,454.3	1,555.9	1,612.4	7.0	3.6
Coal and other solids	207.0	182.0	218.4	(12.1)	20.0
Oil	606.3	655.1	662.6	8.0	1.1
Natural gas	337.8	401.2	430.6	18.8	7.3
Other**	303.3	317.5	300.9	4.7	(5.2)
CO_2 emissions (mn tonnes)***	3,135.4	3,297.8	3,508.3	5.2	6.4
Energy import dependency (%)	47.6	55.0	63.4		
Natural gas import dependency (%)	39.5	52.4	67.3		
Oil import dependency (%)	74.2	83.9	85.9		
Coal import dependency (%)	46.7	52.8	67.8		

**Assumes that EU policies currently in place will be continued. It does not include any policies specifically addressing the climate change issue.*
***Mainly nuclear, hydro and wind.*
****In Kyoto base year 1990, estimated emissions were 3078.7 mn tonnes, comprising electricity and steam production 1212.5mn tonnes, industry 429.9mn tonnes, transport 737.8mn tonnes, other 698.5mn tonnes.*

Source: Energy in Europe: European Union Energy Outlook to 2020, *issued by the Directorate General for Energy.*

Baseline estimates of EU energy, 2000–2020*

enlargement of the Community is implemented. Referring to a total of 10 central and east European countries which are accession candidates, the Communication remarks that these countries are today dependent on Russia for around two-thirds of their natural gas supplies. The gas import dependency of a 25 nation EU, it estimates, would be about 72% by 2020, and its dependency on Russian gas would be about one-third.

Supply security

The issue of supply security has bugged energy policy formulation in western Europe for at least 40 years. Originally, the fear was dependence on Middle East oil, as Europe's demand for fuel oil soared and its total oil consumption increased inexorably by an average of 7%/y. Oil may again become a major concern if the prophets of pending scarcity and rising prices soon prove correct. For the present, however, it is the fast increasing dependence on natural gas which appears most significant. Supplied principally by inflexible pipeline systems from a small number of sources, natural gas is a horse of a different colour from oil. On the basis of present policies, however, it seems unlikely that much effective can be done about it.

The problem, essentially, is illustrated by considering the inherent incompatibility of the main principles of EU energy policy. These are summarised in the new EU Communication as :

- overall competitiveness,
- protection of the environment,
- security of energy supply.

Competitiveness aims at low energy prices in support of European industry. Security of supply, however, demands almost the opposite. Prices must be high enough to ensure investments in exploration and development operations together with investments in pipelines and LNG facilities to transport supplies from increasingly distant sources.

Protection of the environment will be enhanced by increasing reliance on natural gas as the most environmentally favourable fossil fuel. Growing use of natural gas, however, implies increasing import dependence and decreasing security of supply.

Nuclear option

Nuclear power, of course, could provide electricity with negligible reliance on imports and no noxious emissions. However, the problems of disposal of nuclear wastes and the potentially extreme consequences of nuclear disasters, have created a widespread perception that it is not the solution. Japan has tried it in an endeavour to minimise energy import dependence and in pursuit of energy supply diversity. However, recent disasters – albeit on a small scale – have placed question marks on this policy.

Reflecting this viewpoint on nuclear power, the new EU energy analysis anticipates that after about 2015 there will be a decline in nuclear power, due to large-scale decommissioning of nuclear power plants as they pass their already extended lifetimes of 40 years. In the period 2015–2030 it expects that retirements of nuclear plants in the EU will total an aggregate of nearly 110 GW, a figure which compares with total capacity installed in 2000 of 136 GW. While this will spur the demand for natural gas to fuel combined cycle gas turbine (CCGT) plants in replacement, it will result also in higher prices for gas, as rising demand requires supplies from increasingly distant sources. Thus, the report assumes that between 2010 and 2020, the real price of Europe's gas imports will increase by 30% to $19.80/boe in 1990 money, whereas the world crude oil price will increase just 20% to $20.10/boe in 1990 money.

This increase in natural gas prices is expected to contrast with more or less stable real world coal prices resulting in resurgence of coal to generate electricity as the principal replacement for nuclear power. The coal, however, will be imported, not indigenous production. The latter is estimated to decline by 22% between 2000 and 2010 and a further 18% between 2010 and 2020. But net imports of coal are expected to remain at present levels up to about 2010 and then to jump sharply by more than 50% between 2010 and 2020. So much for environmental policies, one may say – but that is how it will turn out on the basis of existing governmental policies, the analysis suggests.

What remedies?

Two main issues are highlighted in these two Energy Directorate reports – environmental pollution and security of gas supply. On the first, the December energy report offers a detailed analysis of how the EU's CO_2 targets could be met without reducing the rate of economic growth. It estimates that the measures it envisages would increase the costs of the EU's energy system by an average of euro 25 bn/y (1990 values). This would be if policies were changed in an optimal way. If they are not, the cost would be higher. An optimal scenario in 2020 would entail, as compared with the estimates in the accompanying table – small reductions in oil consumption and in total energy consumption, a cut of 53% in coal consumption, an increase of 12% in nuclear power and a surprisingly small increase of about 9% in natural gas consumption.

The initiatives outlined to improve security of supply are more nebulous. The Communication expresses the view that 'complacency is not an option for the EU with regard to security of supply. On the contrary,' it says, 'security of energy supply requires continued vigilance and careful monitoring...' It points out, however, that each of the national gas markets has different characteristics, so that rigid EU-wide security of supply criteria and mechanisms do not seem to be the most appropriate response. Based on this prescription, it proceeds to open a Pandora's Box in a recommendation that 'government guidelines combined with licensing systems, agreed industry codes of practice and penalty or incentive systems could provide the necessary instruments...'

In more specific terms, the report on supply security suggests:

- Policies to stimulate economically viable indigenous gas exploration and production.
- Closer cooperation by the EU with external gas producers and transit countries to promote the opening up of oil and gas sectors to attract foreign investments.
- The review and formalisation of emergency procedures in light of the fact that with liberalisation of the markets no single player will necessarily maintain overall responsibility for security of supply.
- Policies to encourage inter-operability of gas networks with different technical and operational characteristics. Aiming at this objective, the Commission is currently preparing a report on possible gas market harmonisation requirements.
- Development of a more formalised system of exchange of information on gas security issues. This might be organised by annual meetings between experts from the various governments, the Commission and companies which could provide advice and assist the Commission in making recommendations for political intervention.
- Strong support by the EU for the work of the Energy Charter Conference to strengthen the international rule of law with regard to energy transit. This should be coupled with increased emphasis on the external dimension of the TEN-Energy (Trans-European Network-Energy) programme.

**Energy in Europe: European Union Energy Outlook to 2020*

Letter to the Editor

Dear Sir,

Liz Bossley's article in your January issue makes a good case for Forties Blend replacing Brent Blend as the UK's 'marker' crude – and, by extension, as the marker crude for most of the world. The reason why it has not up to now, of course, is liquidity. Although Forties Blend production (790,000 b/d in 1998) is well in excess of Brent Blend production (590,000 b/d in 1998, including the Ninian stream), over 200,000 b/d of Forties Blend flows straight into BP Amoco's Grangemouth refinery, so the volume available to other buyers is no greater than the volume of Brent Blend.*

But Brent Blend production is expected to decline over the next few years while Forties Blend production is expected to increase – and, as Liz Bossley notes, there is already a growing wariness about the workings of some aspects of the Brent market. (Her excellent article in the December issue of Petroleum Economist *shows how haphazard the markets for Dated and 15-day Brent can be.)*

So, instead of considering Forties versus Brent, is this not a good time to plan for a new, combined, market in UK crude? A theoretical FortBrent stream, with loadings at Hound Point and Sullom Voe, and with easily established quality and transport differentials to accommodate the two locations, would have the volume and liquidity to satisfy world markets. Nearly 70 fields would produce into FortBrent, and nearly 1,200,000 b/d would be available for tanker-loading – say, 70 trading-sized cargoes each month.

A reasonably informal, but reasonably structured, market could demonstrate efficiency, openness and credibility to users, and to the numerous other producers worldwide which will track it. And the City types playing paper in Brent futures could go back to nurturing their pork bellies.

Martin Quinlan (MInstPet)

** 'Forties blend – an heir apparent to Brent still in waiting',* Petroleum Review, *January 1999, p30–31.*

A new oil province for the 21st century?

Much of the African continent's huge land-mass has yet to be explored by precision seismic techniques. When discoveries are made, geography and politics can stand in the way of exploitation. But, following Sudan's recent emergence as an oil exporter, new opportunities are expected to open up, writes *Martin Quinlan*.

In September 1999, Sudan became the African continent's first new exporter of oil from an onshore field in recent history. The continent's other producers of onshore oil or gas – Algeria, Libya, Egypt, Nigeria and Gabon are the largest – all developed their first fields in the 1960s or earlier, and their fields are generally near their coasts. Sudan's emergence as a substantial exporter therefore proves a point: it is possible to produce oil from the heart of Africa.

But not without great difficulty. Canada's Talisman and its partners in the Greater Nile Petroleum Operating Company had to build a pipeline extending 1,540 km to link the six fields in the south of Sudan to a new tanker terminal on the Red Sea coast (**see 1 on map**). Greater Nile Petroleum says about $3bn will have been spent when planned development work is completed – the sum includes $1bn spent between 1974 and 1984 by Chevron, which discovered the fields but withdrew because of security concerns. Instability continues, with the pipeline already having been damaged by forces opposing the government. Meanwhile, Talisman is attracting criticism for having dealings with Sudan's repressive government.

The benefits are potentially large, however – for Sudan as well as for Greater Nile Petroleum (made up of Talisman 25%, as well as China National Petroleum Corporation 40%, Petronas 30% and the state's Sudapet 5%). Towards the end of last year, three pumping stations on the pipeline had been commissioned and the flow from the six fields – Unity, Heglig, El Nar, El Toor, El Harr and Toma South – had built up to 155,000 b/d. The flow is expected to rise to 225,000 b/d by end-2000, when three more pumping stations should be operational. The production sharing contract under which Greater Nile Petroleum operates provides for the investors and the government to receive flows of oil revenue from the outset.

Capacity of the 28-inch pipeline is nominally 250,000 b/d, but this figure could be raised by the installation of additional pumping stations. There is therefore scope for the pipeline to handle crude from new fields in the area, such as Thar Jath, being appraised by Lundin Oil. Sudan's crude, named Nile Blend, is a low-sulfur light (34°API) stream with similarities to Indonesia's Minas; it has made an untroubled entrance into the market, early cargoes going to Singapore.

Chad faces uncertainties

The problems of long pipelines and political acceptability are familiar to the companies which have been pursuing a plan to enable Sudan's westerly neighbour, Chad, to join the producers. There are strong similarities between both countries' predicaments: Chad's oil, in common with Sudan's, was discovered in the mid-1970s; Chad's economy, like Sudan's, has been ravaged by years of political instability; and both countries have faced the seemingly insuperable task of attracting foreign investments for their respective pipelines. Chad has the additional complication of being landlocked, so its oil will have to be piped across another country, Cameroon, for export.

Despite all the difficulties, it seemed likely last year that Chad's project would go ahead. A group made up of Exxon (now ExxonMobil) 40%, Shell 40% and Elf 20% had established that three fields in the Doba basin – named Komé, Miandoum and Bolobo **(2)** – held reserves of about 1bn barrels. With the participation of the governments of Chad and Cameroon, the companies planned a construction of a 1,050 km pipeline to Kribi, where a tanker terminal was to be sited **(2a)**. A production rate of up to 250,000 b/d of relatively heavy crude was envisaged, with start-up targeted for 2001. With some 300 wells needed, the development was calculated to cost $3.5bn.

However, in November 1999 the project became stalled when Shell and Elf both said that they were not willing to go ahead as planned. The companies have not elaborated on their statements, but it is understood that the size of the investment needed was one cause for concern – particularly for Elf, then in the course of its merger with TotalFina. Political risks might have been another factor, and environmental criticism might have been a third. The route of the pipeline, through remote areas, has attracted the criticism of environmentalists, but ExxonMobil – still strongly supporting the project – has gone to unprecedented lengths to consult and to accommodate the criticisms. At present, ExxonMobil is seeking new participants for the venture.

North African developments

Of the countries with established onshore operations, Algeria is the most expansionary at present. Algeria had already made the deepest inroads into Africa's interior for oil and gas, with gas flowing from Hassi R'Mel, oil and gas from Hassi Messaoud, and oil from fields in the Berkine Basin. Then in March 1999, the large Tin Fouyé Tabankort gas field in the Illizi Basin, some 1,200 km southwest of Algiers, was brought onstream by Total (now TotalFina), Sonatrach and Repsol-YPF, under one of the country's new-style gas agreements with foreign firms **(3)**.

Early this year, according to plan, BP Amoco and Sonatrach should be in the position to make an investment decision on another deep-south project, the development of gas fields in the In Salah area. The two companies' In Salah Gas venture, established in late-1995, has now appraised gas fields in the 23,000 sq km In Salah area, and has been working on engineering options for cutting the cost of the $3.5bn project. Gas is to be piped through a new 520 km, 48-inch pipeline to Hassi R'Mel, for onward transmission to export facilities. Production from the In Salah fields is expected to be between 9bn and 11bn cm/y, of which 4bn cm/y has already been sold conditionally to Italy's Edison, and another 4bn cm/y has been set aside for Italy's Enel.

Algeria's neighbour, Libya, is reckoned to have the gas potential to rival its proven, but under-developed, oil resources. In the 1960s, foreign operators penetrated a considerable distance into the Sirte Basin **(3a)**, and there was every expectation that areas further south would also yield exploitable hydrocarbons. The country's political isolation put the expectations on hold for 30 years, however. The government's claimed new openness to foreign investment, announced last year, has yet to result in new exploration agreements.

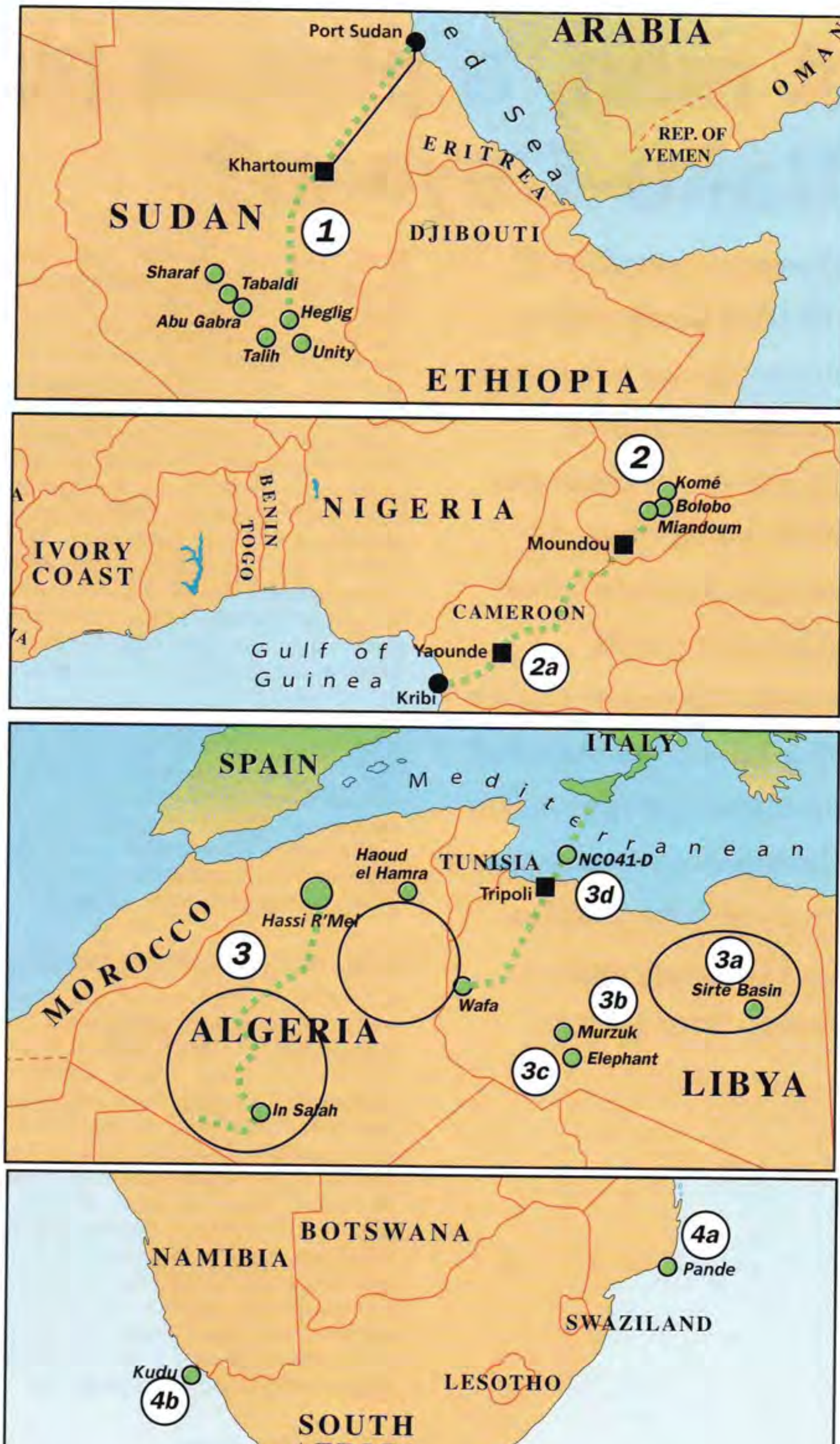
Some onshore work is under way, however. Repsol-YPF is stepping up production from its El Sharara field, a 1996 discovery lying in a new producing area, the Murzuk Basin, in the southwest of the country **(3b)**. Output has now passed 150,000 b/d, and is targeted to reach 200,000 b/d. The second large field in the Murzuk Basin, Lasmo's Elephant, is under development for start-up in 2H2000 **(3c)**. Libya is also set to become a significant exporter of gas to Europe, under Agip's project to construct a pipeline from western Libya to Sicily. Here it will connect with the Italian system. Sources of the gas will be the onshore Wafa field and offshore fields in the NC41 block **(3d)**.

To the east, Egypt is an established onshore producer, with fields in the north of the country and along the Gulf of Suez coast. Its main interest now, however, is the offshore Nile delta area. Tunisia, also, maintains a low level of oil production from onshore fields, although the main interest is offshore.

Exploration potential

The themes of difficult geography and political instability continue to limit African onshore exploration work – and a third, limited or non-existent local markets for gas, can make gas discoveries unattractive. But the potential for onshore hydrocarbons is not in doubt. Onshore Cabinda, for example, is reckoned – on the basis of early exploration work carried out by Gulf (before its acquisition by Chevron) – to be an exploration province of great importance. Three large licences have been designated, with operatorships provisionally awarded to Occidental, Ocean Energy and TotalFina But work in the area is out of the question while Angola's civil war continues – and action by Cabindan separatist groups is likely to be a problem when the civil war eventually ends.

In Cameroon, Gabon, Congo-Brazzaville and Congo-Kinshasa, recent exploration has not extended far into the thick jungle belt. Even in Nigeria, where onshore and swamp fields account for well over half of the country's production, northern onshore areas have not been adequately explored.



In east Africa, the Rift Valley area has interested explorers for many years, and exploration has been carried out by a number of companies. Most recently, Heritage has been carrying out seismic work in Uganda.

Southern Africa has established reserves of onshore gas, notably in the Pande together with Temane fields in Mozambique **(4a)**. Plans to exploit these fields, piping the gas to the northern part of South Africa for industrial use and electricity generation, are still being pursued. However, such plans have always been thwarted in the past by the relatively low price of coal in South Africa, with which the gas would have to compete. The same problem appears to have stalled Shell's plan to develop the large Kudu field, offshore Namibia **(4b)**.

A man, a plan, a pipeline: Baku–Ceyhan?

Molotov cocktails that die-hard Greek leftists hurled during a rampage though downtown Athens on 19 November 1999 weren't the only petroleum carriers that figured in the US President's recent sojourn through Central Asia and southeast Europe. So too did pipelines intended to criss-cross the Caspian and Caucasus regions, writes *Peter S Adam*.

During a summit of the Organisation for Security and Cooperation in Europe (OSCE) in Istanbul on 15–18 November last year, the Presidents of Azerbaijan, Georgia and Turkey signed an accord paving the way for a US Government-supported pipeline linking Baku on the Caspian to the Turkish port of Ceyhan on the Mediterranean. This was a big step forward for the Clinton Administration. Multiple, east–west pipelines exporting Central Asian oil, which would avoid Iran completely and offer alternative(s) to routes through Russia, have been one of the few high profile international energy objectives it has pursued with conviction.

And now, as development of Central Asia's oil and gas resources shift into high gear, the demands of global realpolitik are asserting themselves with stepped up intensity. The trade-offs, US policy makers and elsewhere – and the international oil companies involved – are being forced to make are tough.

Long pipelines, short tempers

Left adrift in the wake of the Soviet Union's collapse and sitting aside the European/Asian fault line running north–south across Russia, whatever happens in the Caspian/Caucasus region has strong international implications, and its problems defy easy solutions. The Caspian's hydrocarbon resources are said to be on a North Sea order of magnitude. It's newly formed political systems are fragile; it is close to Russia, Iran, India and China and vulnerable to foreign interference. In addition, its different ethnic groups don't always get along; and it is landlocked, thus requiring pipelines to transport oil and gas out.

Turning the key

The degree to which the fortunes of the international oil companies present in the region are intertwined with the major political powers is revealed by events leading up to the OSCE summit. A month prior to the meeting, BP Amoco, which enjoys a dominant 34% in the Azerbaijan International Operating Company (AIOC) Consortium, dropped its opposition and gave tacit approval to the Baku–Ceyhan route, paving the way for the pipeline accord that the region's Presidents signed.

The US petroleum industry as a whole has deep reservations about multiple east–west pipelines which, as Larry Goldstein of the Petroleum Industry Research Foundation (PIRA) notes 'have always from an economic perspective been suspect'. Big US oil feels, not without some justification, that at least some of the east–west pipelines may be white elephants. After all, few sizeable new discoveries of any note have been made in Central Asia since the Soviet Union imploded and the states there became independent. And the region's oil and gas resources – estimated to range from 60mn to 140mn boe – may not warrant all the new high-calibre export capacity the US Government would like to see built in Central Asia.

Nonetheless, in addition to assuring that Russia (or Iran or any other state) can unilaterally cut off exports of petroleum from the region, multiple transport routes meet overriding (and presumably Western) geostrategic objectives. These include:

- Paying back Turkey for being a good member of NATO and a stalwart, and not anti-Israeli, US ally in the Middle East.
- Shoring up the Central Asian states politically, thus protecting them from Russia, and to a lesser extent, Chinese and Iranian influence.

Domestic US political considerations also may be playing into fast tracking the Baku–Ceyhan facility. In the wake of his impeachment, and the Senate's decisive rejection of his Nuclear Non-Proliferation Treaty, the increasingly lame-duck President is looking for successes abroad to burnish his tarnished legacy. Helping lay the groundwork for stability in the Caucasus and Caspian region would do so nicely.

The Central Asian governments, understandably, are eager to go along. They stand to benefit greatly from transit fees and an economic 'shot in the arm' from the project. The Baku–Ceyhan pipeline alone could cost as much as \$4bn. US Government-backed pipelines would be good for assuring America's continued counter-balancing to the influence of Russia, Iran and China in Central Asia.

The heart of the matter

BP Amoco's change of heart has been a key issue – its dominance in the AIOC helps ensure that the other consortium

members (Exxon, Amerada Hess, Unocal and Pennzenergy) will follow suit with regard to the pipeline.

The company's decision to approve the pipeline project is attributed to three different factors:

- Its recent gas and condensate discoveries in the Shah Deniz field in the Azeri section of the Caspian will have a positive impact on the pipeline's economics, both in terms of volumes and the nehancement of crude steam quality.
- Its sense that US Government opposition to a pipeline through Iran is not likely to lessen any time soon.
- Fears that the US could well take a dim view of the company's acquisition of Arco, if it were to oppose the Baku–Ceyhan route.

More mundane considerations probably also played a part: increased tanker congestion in the Bosphorus as Caspian production picked up; political uncertainties in Russia which have made continued reliance on their pipeline systems too risky; and a general recognition that since the US saw its geostrategic interests at stake here, opposition to US Government preferences would be futile.

No-one seriously expects that BP Amoco and/or the other members of the AIOC will pick up the tab for the pipeline without the involvement of the multilateral financial institutions. But the price for BP Amoco's acquiescence to the Baku–Ceyhan pipeline could be high in terms of vulnerability to Russian retribution.

Officially, BP Amoco says it doesn't see it this way, but the company, it seems, is being badly burned in Russia. Already: the asset stripping of Sidanko, a 'bankrupt' oil and gas company in which it has a half-billion-dollar investment, may well be underway. And this is not BP Amoco's only Russian involvement. The proposed acquisition of Arco could give BP Amoco a sizeable stake in Lukoil, Russia's third-largest oil company. Furthermore, BP Amoco had, and perhaps still has, hopes to build a pipeline from Siberia to China.

Raising the stakes

The Russians see the US involvement in Central Asia's pipelines as unnecessary meddling in their back-yard. Adding petroleum transport capacity in Central Asia will have a deleterious impact on the economics of Russia's entire petroleum sector. 'To operate optimally, Russia's extensive petroleum pipeline system needs Caspian oil,' notes international pipeline expert Richard Hildahl. 'Taking Central Asia's oil out through other facilities raises the per unit costs of exported Russian oil tremendously.'

To give an idea of the severity of the impact, Hildahl points out that 'it costs roughly seven times as much to produce and deliver one barrel of oil for export through the Russian pipeline system as it does to produce a barrel in Saudi Arabia'. Saudi, of course, isn't landlocked and is easily accessible by the sea. In addition, excess pipeline capacity in the region leaves Russia vulnerable to the machinations of Opec, particularly Saudi. 'All the Saudis have to do is turn open the spigot and the economics of Russian oil exports go down the drain.' Furthermore, increased supplies of Central Asian oil in the Mediterranean will force down prices of Russian oil, as well as gas, to Europe.

Despite US noises about their taking a piece of the Baku–Ceyhan pipeline, it is a losing situation for the Russians all round, particularly, as Hildahl points out, since Russia's exportable oil and gas surplus is likely to decline precipitously in the years ahead, meaning even greater per-unit transport costs for its oil.

Former reds and blues

In addition, Russia has pipeline plans of its own in Central Asia. It is planning a new pipeline – 'Blue Stream' – linking Russia to Turkey across the Black Sea to secure its share of the growing Turkish gas market. But Turkey could also be supplied by an alternate pipeline under the Caspian Sea from Turkmenistan. Turkmen natural gas is currently sold to Russia for transport at a discount. Subsurface Caspian lines, linked up with the Baku–Ceyhan facility, could also transport Kazakh oil through Central Asia, instead of through Russia as is now the case.

Other critics of US pipeline policy in Central Asia take a somewhat different tack. Barbara Conry of the Cato Institute points out that it is hypocritical for the US to tell the Russian reformers that governments should stay out of businesses generally, while pushing Central Asian governments to go into the pipeline business.

And the James A Baker III Center at Rice University makes a case – which has been the basic position of big oil in the US – that the Baku–Ceyhan route doesn't have much going for it economically; that the US should try for a rapprochement with Iran and accommodate Russia's interests in Central Asia; and that a more precisely calibrated case-specific approach to stability in the Caspian region could further US interests.

Mother Russia

Washington sees things from a different perspective. It is not only the Clinton Administration which strongly supports multiple pipelines out of Central Asia, but also the national security and intelligence communities, including the Pentagon. And it is not just an exaggerated desire to play a 21st century version of the 'Great Game' at work here. After all, the military and its intelligence apparatus have to deal with potential instability in the Caspian region.

With regard to pipelines south from Central Asia to the Persian Gulf, the US Government – any US Government – would think twice about supporting them. But policies viz-à-viz Iran are evolving and a southern pipeline route could also make economic sense, depending, of course, on how much oil is actually found in the Caspian. At the end of the day though, Russia is the big concern. US policy makers with long experience of dealing with Russians, like them but don't trust them not to use petro-politics to try to control the states of Central Asia. The opposition of the petroleum industry is of less concern – companies' reservations about multiple, east–west pipelines could well dissipate if any of the wells now being drilled come in gushers, and/or economic recovery in the Far East is more robust than expected, or if Russia's campaign in Chechnya becomes particularly odious.

A few years ago, management guru Peter Drucker noted in his book *The New Realities* that: 'The major "new reality" in international affairs... remains the coming dissolution of the Russian Empire.' He asked: 'Is any government, any politician, any political thinker prepared for it?'

Not yet. But supporting pipelines that will shore up Central Asia against the reverberations of the unravelling of Russia's empire is a positive step – not without risk, of course – and one that US Governments, regardless of their ideological predispositions or sympathies with major oil company interests, will find hard not to take. Petroleum is just too important to be left to free enterprise, which in any case is never free from political interference, particularly in the Caspian/Caucasus.

The corridors of power

As US Secretary of Energy Bill Richardson puts it, the establishment of a Eurasian energy corridor 'is not just another oil and gas deal. It is a strategic framework that advances America's national security interests.' That the US is in this game is a given. Whether its pipeline policies exacerbate or mitigate the problems that developing the Caspian/Caucasus region oil and gas resources involves remains to be seen.

It was Winston Churchill who observed that Russia 'is a riddle wrapped in a mystery inside an enigma'. But he also counselled: 'In victory, magnanimity.' The West has delivered Russia a painful defeat in the Cold War, it is going to be tough playing the 'Great Game' in Central Asia with a wounded bear. Let's hope that corporate executives and political leaders are up to finessing this one.

World development of production sharing agreements

In the mid-1960s the large foreign oil companies (FOCs) were not at all keen to sign the then newly introduced production sharing agreements (PSAs). However, over time, these have become one of the most common contract types. *Kirsten Bindemann of the *Oxford Institute for Energy Studies* looks at how the different types of PSA contract have developed around the world.**

Under a PSA the FOC receives a share of field production as a reward for its investment and operating costs and the work performed. It usually bears the entire exploration cost risk and shares the revenue risk with the host country. The contract is signed before exploration begins and the foreign partner will therefore expect significant rewards later on in the life of the contract.

The FOC's revenue is made up of cost oil and profit oil, while the direct sources of revenue for the government can comprise royalties, profit oil, bonuses, taxes, customs duties, and indirect benefits that arise from price caps and domestic market obligations (see **Figure 1**).

PSAs do not divide profits out of market proceeds but instead divide the physical production after allowing a portion of output to be retained by the FOC for the recovery of pre-production and production costs. This means that costs can only be recovered once oil is produced. The sharing of production follows a pre-agreed split between the FOC and the state or its national oil company (NOC).

PSA development over time

An empirical analysis of 268 PSAs signed by 74 countries during the period 1966–98 shows that the contract form has changed substantially over time. The following summarises the main contract elements.

Royalties

Royalties here refer to the maximum rate payable. While most PSAs levy fixed royalties, some contracts incorporate sliding scales. Since this research is based on the contract terms rather than the productivity of the fields in question we do not know the actual royalty rate if a sliding scale is applied. Therefore, the maximum possible rate is taken for the purpose of comparison. Among the countries that offer sliding scale royalties are Algeria, Egypt and Nigeria.

During the period 1966 to 1998 royalties in Asia and Eastern Europe have on average been much lower than those in other regions. The average royalty rates in Asia and Eastern Europe were below 4% and 5%, respectively, whereas one could observe average royalties between 7% and 9% in the rest of the world. One explanation for this divergence is the absence of royalties in many Asian PSAs, in particular in the Indonesian contracts. In place of royalties Indonesian contracts provide for first tranche petroleum (FTP) of 20%. This is shared between the two contracting parties according to the agreed profit-oil split but works otherwise in the same way as a royalty payment. The picture is thus somewhat distorted.

Like most other PSA parameters royalties are occasionally negotiable, or biddable, which means that for some agreements there is no information on actual payments. Another contributing factor to the divergence of royalty rates is the spread between the highest and lowest rates levied within regions. In Asia royalties vary between zero and 12.5%, in Eastern Europe between zero and 17.5%. In all other regions the variation is at least 20%.

Net exporters charge significantly higher royalties than net importers, and, not surprisingly, onshore contracts are relatively tougher for FOCs than offshore agreements.

Cost oil

Approximately one-third of PSAs specify annual cost oil allowances either on a sliding scale or, with regard to model contracts, state that this variable is biddable or negotiable up to a certain maximum value. Cost oil allowances vary from zero in some Libyan, Peruvian, Romanian and Trinidadian contracts to 100% in countries such as Indonesia, Algeria and India. It should be noted here that not all PSAs in the countries concerned carry the same cost-oil clause.

Since 1966, cost oil has on average been lowest in the Middle East with 37%, and South America and North Africa with 45% and 49% respectively. The most generous treatment of cost recovery could be found in Asia with 66% and in Central America with 69%. As with royalties, there are significant variations in cost recovery limits within regions. The difference between highest and lowest maximum cost oil during the period 1966 to 1998 is 100 percentage points in Central America, Eastern Europe, North Africa and South America. In Asia cost recovery levels range from 20% to 100%. Variations in the Middle East and southern/central Africa contracts are similar with 25% to 100% and 30% to 100% respectively.

Two somewhat surprising results are that overall onshore cost oil is more generous than the offshore rate, and that there appears to be no difference between exporters and importers.

Almost half of all contracts specify cost oil at either 40% or 100%, while almost one-third are at 30% or 50%. At the other end of the scale, 0% cost oil features in only 2.5% of PSAs. Apart from a high concentration on only a few allowances, there appears to be a preference for round numbers. We are more likely to find cost oil specified at 40% than at, say, 45%.

Profit oil

Only 45 of the 268 PSAs considered have fixed profit-oil shares, all others have some kind of sliding scale which is either based on output or rate of return. Given this bias in favour of sliding scales we have to reflect on the maximum and minimum values. The following figures are based on the FOC share but the government or NOC share can easily be calculated by deducting the FOC share from 100.

During 1966 to 1998 the highest maximum profit-oil share for FOCs could be found in Central America with 65% and by far the lowest in the Middle East with 28%. The latter also offered the lowest minimum share with 16%, whereas Central America, Eastern Europe, and South America, with up to 39%, granted the most generous minimum shares to FOCs.

Again, the reader should be reminded that we consider contracts rather than production levels and thus have no information on the actual profit oil distribution. Nonetheless, we obtain a good approximation of how output might be divided. The spread between highest and lowest maximum varies from 10 percentage points in South America to 85 in Asia and southern/central Africa. This is not surprising since the maximum profit oil for FOCs in South America is only 50% compared to 100% in the latter two regions.

It is noticeable that offshore sliding scales are usually volume rather than rate-of-return based. For both variables exporters offer less favourable conditions to FOCs than importers.

As with royalties and cost oil both minimum and maximum profit-oil shares tend to cluster around certain values. More than one-third of contracts have a minimum profit-oil share for the FOC of either 10% or 30%. Altogether two-thirds specify minimum profit oil between 5% and 30%. A similar picture emerges with regard to maximum profit oil. One-quarter of all contracts specify this at either 40% or 50%. Almost 30% of contracts opt for a maximum of more than 50%.

For all variables considered so far, we observe that there are many small steps at the lower end of the respective scales, and only a few big steps at the upper end of the scales.

Duration of contract

Although over time both minimum and maximum exploration periods have varied substantially between regions a relatively high degree of convergence can be observed at present. The only notable exceptions are the Middle East and South America who both offer shorter than average exploration times as well as southern/central Africa with well above average duration. Maximum production periods reveal greater divergence and range from 23 years in the Middle East to 30 years in South America.

The percentage of the contract area that has to be relinquished at the end of the first exploration period ranges from 20% in Asia to 35% in southern/central Africa and Eastern Europe.

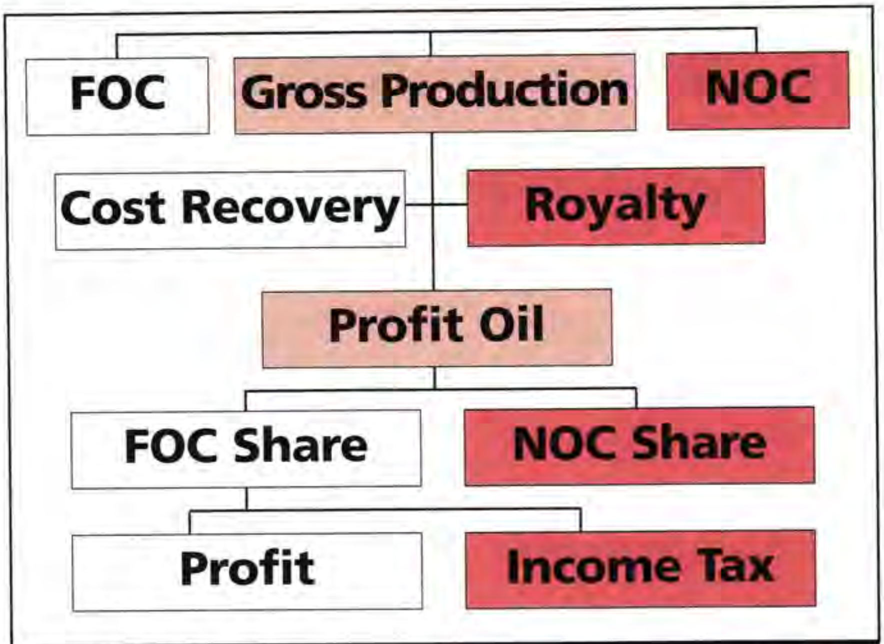


Figure 1: Basic PSA Features

Bonuses

Only very few PSAs demand the payment of, usually very small, discovery bonuses. Both signature and production bonuses display a strong divergence between regions. Generally, Eastern Europe tends to be at the lower end of the scale and the Middle East at the upper end.

While production bonuses are similar for onshore and offshore contracts, the former require notably higher signature bonuses than the latter. By the same token, exporters charge higher bonuses than importers, with some Opec countries behaving like an importer with regard to signature bonuses and like an exporter with regard to production bonuses.

Over time signature bonuses have been lowest in Eastern Europe and Asia, and highest in the Middle East and Central America. Production bonuses, on the other hand, were on average lowest in Eastern Europe and Central America, and highest in the Middle East and Asia as well as in southern/central Africa.

Taxation

For the purpose of this study we are not so much concerned with the tax rate, which varies widely, but with the payee. In about one-third of all contracts contained in the dataset the tax is paid by the FOC. Almost 20% of PSAs specify that the NOC has to settle the tax bill on behalf of the FOC. A further 20% of contracts waive any tax liabilities. In many cases income tax is negotiable.

Overall assessment

With regard to PSA terms there is competition among governments between regions, but even greater competition within regions. This implies that one cannot refer to, say, a typical Asian or a typical Eastern European contract.

Overall, offshore PSAs are more favourable for the FOC than onshore agreements. The difference is, however, not quite as marked as one might expect. There is a much clearer distinction between exporting and importing countries with the former generally offering tougher conditions.

While it can be shown that PSAs have undergone changes in the 1990s, it is not possible to pinpoint these alterations in the contract parameters as a response to increased competition from new players such as the Caspian countries. Furthermore, there is no clear-cut evidence that countries with large reserves of crude oil offer tougher contract terms.

*Kirsten Bindemann's book entitled *Production-Sharing Agreements: An Economic Analysis* was recently published. See p43 for review.

North Sea oil topping out

Chris Skrebowski reviews exploration and production activity in the North Sea over the past year and assesses future prospects.

The year 2000 promises to be a relatively quiet one in terms of the start-up of new North Sea oil production. In contrast, 1999 proved a very successful year, with most projects anticipated to start-up in the year doing so. Around 1.2mn b/d of new capacity was added, although peak rates will, in some cases, take time to achieve. Some had, however, originally been slated for 1998 start-ups.

At the end of 1999 in the UK sector the start-up of the Triton project (Bittern, West Guillemot and NW Guillemot) had slipped to an early 2000. The delay was caused because the newly converted *Triton* FPSO remained storm-bound on Teesside rather than being able to start hook-up work in the field. The only other 'no shows' were the small Halley project – an Amoco project put on hold following the BP Amoco merger – and Kyle which has now become a 2Q2000 start-up following delays to the installation of more capacity on the *Banff* FPSO.

In the Norwegian sector the small STUJ project was put on hold but all other fields started-up as anticipated, as did two Danish fields and the Dutch D15 block field.

Work-starved contractors around the North Sea will be pleased to note that so far this year a number of small projects have been announced. At the time of writing, Phillips had announced the go-ahead for the Jade field, awarding the platform contract to Kvaerner. Although this will provide work for the Methil construction yard from this year, production start-up is not scheduled until late 2001. However, these small projects are mostly single well subsea tie-backs – Cook, Gannet E Phase 2, Lomond 2, South Everest – or a single deeper well within a field – Kingfisher Phase 2. This means the only projects that will contribute significant new oil/liquids production flows are Elgin/Franklin and Shearwater, both of which are gas and condensate fields, and the delayed Triton project. When combined with the smaller Cook, Kyle and Captain B flows, the UK will gain potential additional peak oil flows of roughly 0.5mn b/d in 2000.

In contrast, the gains in Norway and Denmark will be small. In the case of Norway, this is the result of political decisions to delay developments and to cut back production to support Opec's actions in strengthening oil prices. Additional production capacity is, however, needed to offset the decline in flows from the older North Sea fields. Already decline rates in the UK and Norwegian sectors are in the 6–6.5%/y range, which means annual additional capacity of around 120,000 b/d from the UK sector and over 200,000 b/d from the Norwegian sector is needed just to maintain production levels.

All-time highs

It is becoming increasingly clear that the first and second quarters of 2000 are likely to be the UK sector's all-time peak production level. After that there is no chance that anything other than the development of a totally improbable new giant field would be large enough to more than offset natural declines.

In Norway, the deliberate restraint of output and development also means that 2000 is likely to witness the all-time peak in their production levels. The question thereafter is the degree to which new developments and enhanced recovery can slow the production decline. In the UK sector, 2001 will definitely see first production from the 16,000 b/d Jade field and the rather larger Blake field where reserves are pegged at 50–75mn barrels.

BG International is to develop Blake as a six-well tieback to the Ross field's *Bleo Holm* FPSO. The £158mn project is due onstream in August 2001, with peak production of 40,000 b/d.

As we showed in the September 1999 issue of *Petroleum Review* (p33–35), there are a large number of possible developments (often potential tie-backs) with reserves of 10mn to 40mn barrels. In addition, there are three rather larger fields – Mobil's Skene field which has resources of 65mn barrels, TotalFina's Pilot field with nearly 80mn barrels and, largest of all, BP Amoco's West of Shetland heavy oil Clair field with 5bn barrels of oil in place and recoverables of 250–500mn barrels (5–10%).

The fact that Norsk Hydro has decided to develop the 700mn barrel Grane heavy oil field, often described as Norway's largest undeveloped field, suggests that the Clair accumulation is also likely to be developed, barring an oil price collapse. The other large Norwegian fields already scheduled for development are – Snorre B in 2001, Fran/Gjoa in 2004 and Kristin, also in 2004. BP Amoco's Skarv field is another definite development, although timing is currently uncertain.

Future decline

The conclusion is inescapable – barring a series of near miraculous finds – the North Sea's two main producers will achieve all-time production peaks in 2000 and then decline. The speed of this decline will be determined by the companies' success or otherwise of developing small accumulations and enhancing recovery from existing developments. Slightly surprisingly, the relatively small Danish sector is unlikely to peak before 2001/2002 as Maersk's large Nana field will not come onstream until 2001.

According to the IEA's latest forecast, UK production – including natural gas liquids (NGLs) – should reach 2.9mn b/d in 2000, for a 60,000 b/d gain on 1999 levels. This contrasts with Petrodata, who anticipate production of 2.89mn b/d for a 65,000 b/d fall. Unless a metaphorical rabbit is pulled from the North Sea, the year 2000 will go down as the year North Sea production peaked.

Gas outlook

In terms of new gas supplies 1999 was also a highly successful year with Conoco bringing their Viking Phoenix, NW Bell, Jupiter II (Europa, Callisto North and Sinope) and Vampire field projects onstream. Shell flowed the Corvette, Ketch and Gadwall fields. BP Amoco's Bell came onstream on 5 Jan 2000. BG brought the Neptune and Mercury fields onstream as part of the ECA (Easington Catchment Area) project and Burlington Resources brought their Dalton field in the Irish Sea onstream.

For 2000, the development outlook is currently more subdued although short development times means more projects could emerge as the year progresses. The two major gas/condensate projects – Elgin/Franklin and Shearwater – will make the largest gas additions in 2000 but will be aided by the development Conoco's Vixen and Callisto North fields, BP Amoco's South Everest and Burlington's Millom West in the Irish Sea.

The year's largest single gas addition will however come from the Norwegian sector with the start-up of Åsgard B.

North Sea Oil fields starting up in 1999 Name	Operator	Start-up	Peak prod'n (b/d)	Prod'n system
UK				
*Banff	Conoco	Feb	55,000	FPSO
*Buckland	Mobil	Oct	30,000	subsea
*Egret	Shell	Feb	9,000	subsea
*Gannet G	Shell	Jul	8,000	subsea
*Janice	Kerr McGee	Feb	45,000	semi-sub
*Orion	Talisman	Sep	14,000	subsea
*Pierce	Enterprise	Jan	45,000	FPSO
*Renee/Ruby	Phillips	Feb/Apr	24,000	subsea
*Ross/Parry	Talisman	Apr	40,000	FPSO
Total			**271,000**	
Norway				
*Asgard	Statoil	Apr	270,000	FPSO
*Balder	Esso	Oct	75,000	FPSO
*Borg (H Centr)	Saga	Jul	25,000	subsea
*Jotun (Eli/Tau)	Esso	Oct	80,000	FPSO
*Øseberg E	Norsk Hydro	May	90,000	platform
*Rimfaks	Statoil	Feb	55,000	via Gulfaks A
*Troll C	Norsk Hydro	May	100,000	semisub
*Visund	Norsk Hydro	May	100,000	platform
Total			**795,000**	
Denmark				
*Siri	Statoil	Feb	50,000	platform
*South Arne	Amerada Hess	Jul	45,000	conc plat
Total 95,000				
Total North Sea (1999)			**1,161,000**	

Oil fields starting up in 2000				
UK				
Bittern**	Amerada Hess	Jan–00	60,000	FPSO
Captain B	Texaco	end–00	25,000	platform
Cook	Enterprise	May–00	20,000	2 subsea wells
Curlew Phase 2	Shell	Mar–00	10,000	1 subsea well
Elgin/Franklin	Elf	Jun–00	216,000	platform
Gannet E Phase 2	Shell	3Q00	15,000	1 subsea well
W&NW Guillemot**	Amerada Hess	Feb–00	33,000	FPSO
Keith	BHP	end–00	10,000	1 subsea well
Kingfisher Phase 2	Shell	Jul–00	7,000	1 subsea well
Kyle	Ranger Oil	2Q–00	20,000	subsea
Shearwater	Shell	Jun–00	82,000	platform
Total			**498,000**	
Norway				
Øseberg South	Norsk Hydro			platform
STUJ	Saga	mid–00	6,000	subsea
Sygna	Statoil	Aug–00	40,000	subsea
Total			**46,000**	
Denmark				
Amalie	Danop	2000	7,000	
Gert	Maersk	2000	6,000	
Halfdan	Maersk	end–00	10,000	via Dan
Total			**23,000**	
Total North Sea 2000			**692,000**	

**In production ** Triton project*
Source: Wood Mackenzie, Petroleum Review

Fast-track development of Sakhalin II

Russia's troubled politics, its labyrinthine system of regulation, and its dire economy, makes life difficult for all those seeking to do business in this vast country. But the foreign oil companies developing the oil and gas fields offshore Sakhalin Island, in the Russian Far East, have also had to cope with ice, heavy seas and a lack of adequate transport and communication systems. *Jeff Crook* reports.

Against this background, the start of production from Sakhalin II in July 1999 was an extremely impressive achievement, particularly since the project only got underway three years earlier in June 1996. Such a relatively fast-track schedule was achieved by converting an existing facility to exploit the reserves – building a new facility could have added up to two years to the programme.

The early production facility – called the Vityaz Production Complex – produces oil from the Astokh portion of the Piltun-Astokhskoye field and is located in the Sea of Okhotsk, some 16 km off Sakhalin Island's northeast coast. The complex was named by the Governor of the Sakhalin Oblast. 'Vityaz' means 'Honorable Warrior' in the local tongue, and the name provides an indication of the importance of the project to this desolate island.

Sakhalin II is being developed by Sakhalin Energy Investment Company Ltd – a project company established in April 1994. The shareholders are: Marathon Sakhalin (37%), Mitsui Sakhalin Holdings (25%), Shell Sakhalin Holdings (25%) and Diamond Gas Sakhalin, whose parent company is Mitsubishi (12.5%). The combined reserves of the Piltun-Astokhskoye and nearby Lunskoye fields are thought to be 1bn barrels of oil and 14tn cf of gas. According to Sakhalin Energy, the overall investments in the project to date are around $1bn.

Russian first

As oil started to flow from Sakhalin II in July 1999, Sakhalin Energy claimed that it had become the first enterprise to develop oil and gas resources in Russia under a production sharing agreement (PSA). 'This event is extremely gratifying in that it represents the culmination of nearly a decade-long effort,' announced Alan Grant, President of Sakhalin Energy. 'Working together with the Russian Federation and Sakhalin Oblast administrations, we have overcome regulatory and geographic challenges.'

The Vityaz complex consists of an Arctic-class drilling and production platform, which was previously called 'Molikpaq' (pictured), together with a single-leg mooring buoy (SALM) and a double-hulled, million-barrel floating, storage and offloading (FSO) vessel named *Okha*. Production from this complex will only take place during the ice-free period during the summer months. The FSO is classed as a tanker and will be able to trade in the international tanker market during the winter months.

Ice sheets up to 1.5 metres thick may occur in the field location during the winter, with broken ice forming rubbles up to 25 metres thick. Icing of vessels is a serious problem, and intense snow storms have also to be endured. Dangerous storm winds and slamming waves also present a problem during the summer months and there is risk of earthquakes in the region.

The Molikpaq platform is a gravity based structure with a substantial steel skirt which provides ice protection. The unit was originally built in 1984 for operation in between 15 metres to 20 metres of water in the Beaufort Sea in the Arctic Region of Canada. The unit was taken out of service in 1990 and was mothballed by its owners, Gulf Canada. It was found to be in good order when inspected for the Sakhalin project, although many of the systems needed upgrading or replacing.

The ice conditions in the Sea of Okhotsk were regarded as less severe than those found in the Beaufort Sea – but the sea conditions were harsher. The water is also 10–15 metres deeper at the field site. The water depth and sea conditions were important considerations during project planning – the platform layout and orientation needed to be carefully studied with wave deflectors being added during the conversion. Tank testing was used to assess the design.

Unit conversion

After satisfactory inspection, the 38,000-tonne Molikpaq was purchased by Sakhalin Energy and was towed to Korea for conversion by Daewoo Heavy Industries (DHI). During modification, the living quarters were fire protected, production facilities with capacity of 90,000 b/d of oil and 70mn cf/d of gas were installed, and drilling facilities were expanded to cater for up to 32 wells.

A new process module weighing 2,250 tonnes was constructed and installed on the deck. Other modifications included raising the drilling rig by five metres to create space around the wellheads, installing a new top drive unit, refurbishing the drilling derrick, installing a new 4.5-MW generator, installing a flare stack and replacing most of the safety systems.

As the water depth was 30 metres in its Sakhalin location it was necessary to raise the unit above the seabed in some way. One possibility was to construct a submerged, rock armoured 'berm' for the platform to stand on. During studies of this option a programme of tank tests was carried out on a 1:40 scale model in a multi-dimensional wave tank at the Canadian Hydraulics Centre in Ottawa.

However, it was finally decided to construct a steel spacer to increase the height of the platform base. The spacer design would also serve to strengthen the platform against the harsh environment in the region – the overall structure was designed to resist simultaneous ice and seismic forces.

Russian contribution

Fabrication of the steel spacer proved a significant Russian contribution to the project. A $35mn contract was awarded to the Amur Shipbuilding Plant, at Komsomolsk-on-Amur, for construction of the unit. The Rubin Central Design Bureau for Marine Engineering and the Krylov Shipbuilding Institute, both based in St Petersburg, were among the organisations who assisted with the design of this unit.

The project will have great significance for the future involvement of Russian companies in other oil and gas development programmes. When the then President of Sakhalin Energy, Frank Duffield, announced the contract, he said: 'We have looked carefully at Amur Shipbuilding's capabilities and we are satisfied that they can meet the high standards of work and the very challenging schedule that we require. Successful completion of this contract is likely to be significant because it will provide a solid foundation for future participation of Russian suppliers in the development of the Sakhalin Shelf.'

The spacer weighs 14,700 tonnes and measures 110 metres long, 110 metres wide and 15 metres deep. Mating it to the Molikpaq was carried out in deep water. During this process the spacer was held in place by 10 anchors and kept in neutral buoyancy. It was then necessary to align the spacer precisely with the docking points on the Molikpaq. DHI installed three underwater cameras for this purpose and made alignment markings to allow the mating positions to be monitored. When everything was confirmed to be correct, compressed air was used to expel the water from the spacer until the platform was raised. This was a very slow and careful operation to achieve an accuracy of less than 50 mm tolerance in the sea mating.

Production from the Vityaz complex began on 5 July 1999, with one well flowing at a restricted rate while the platform facilities were being commissioned. Production will initially be limited to the ice-free season of the year and is expected to reach 90,000 b/d by the start of the production season in 2000. Associated gas will be re-injected into the reservoir until facilities for transport are in place.

FSO specs

The FSO *Okha* is, in fact, a Suezmax tanker of 158,000 dwt. The vessel fully meets the ABS Ice Class Notation DO allowing it to operate in the polar regions and is classed both as an FSO and as a trading tanker. It is powered by a diesel main engine and has a service speed of 15.2 knots. The vessel is equipped with a laboratory unit enabling analysis of crude oil, and with a metering skid to accurately measure the volume of oil offloaded.

The overall FSO system includes a novel SALM type mooring with a fluid transfer system, designed to withstand the severe weather and ice during the production season from June to December. At the end of the season the *Okha* will be disconnected and the SALM ballasted down into a special dredged area, thus avoiding damage from ice.

The FSO system is operated by Sakhalin Marine Ltd, a joint venture between Sakhalinmorneftegas (50%), Single Buoy Moorings (25%) and ICB Shipping (25%) and is chartered to Sakhalin Energy.

Sakhalin Energy has stated that the support from both the Russian Federation and the Sakhalin Oblast, and participation of Russian technical institutes and Russian industry have been instrumental in achieving first production on an accelerated schedule from the commencement date of the project in June 1996. Although some of the gloss of the achievement was taken off when an oil leak was reported towards the end of September last year.

Future development

With oil starting to flow from Sakhalin II the next stage of development may involve the massive gas reserves in the region. The signs are that gas markets and methods of gas export are being studied. Of course, it would make sense for all the companies to cooperate over the gas export infrastructure, but there is a difference of opinion between the those involved.

Sakhalin Energy, operator for the Sakhalin II consortium, says that its plans for gas are based on building an LNG (liquefied natural gas) plant on the shore. The company sees potential markets for LNG exports in Japan, Taiwan and China.

However, Exxon Neftegas, operator for the Sakhalin I consortium, appears to favour a pipeline. The company initiated a study to examine the feasibility of natural gas deliveries to Japan, during May 1999. The feasibility study is looking at pipeline route selection, design standards, environment and regulatory considerations.

Staring into the abyss

Just when it seemed that there was a decisive government push to move ahead with several oil projects requiring foreign investment, Ecuador was plunged into the worst economic crisis of its history and the country is now technically bankrupt. *Maria Kielmas* reports.

A combination of low world prices for oil and bananas, Ecuador's major export commodities, in 1997, coupled with economic losses from widespread damage by the El Nino climatic effect in 1998 and controversial government bailouts of bankrupt private banks in 1999, have resulted in a 7.3% slump in GDP last year. Other economic indicators provided in January by the central bank are dire. The liabilities of the public, financial and private sectors amount to \$24.229bn – a figure which is \$7.41bn more than these sectors' assets.

In 1999 Ecuador registered a 6% current account deficit and a 4.7% GDP budget deficit; inflation at 60.7%, which is Latin America's highest. Its currency depreciated from 7,000 sucres to the US dollar in January 1999 to 29,000 sucres in January 2000, when President Jamil Mahuad announced that it would be pegged to the US dollar.

In September 1999 Ecuador was the first country to default on Brady bond payments, a form of restructured public sector debt backed by US treasury notes, followed later by default on eurobond payments. The country's foreign debt is \$16.67bn, some 98% of GDP, of which \$6bn is Brady debt and \$500mn is in eurobonds. The rate of economic decline in 1999 was so fast that even rising world oil prices could not give the Ecuadorian economy a breathing space.

Oil lifeline

Increased foreign investment in the oil sector was to provide the main lifeline for the economy and 2000 was to be a decisive year for Ecuador's oil industry. Government oil policy was firmly in the hands of Economic Secretary, Javier Espinosa Tern. A former Energy Minister and probably the most professional holder of Ecuador's most politically precarious 'revolving-door' Ministry where Ministers usually last an average of six months, Espinosa survived over three years between 1984 and 1987.

In October 1999 President Mahuad appointed Espinosa Economy Secretary of State, an economics supremo in charge of the Finance and Energy Ministries. In December, Espinosa's ally, Wilson Pastor – lately Manager for Triton Energy in Ecuador, and previously Head of state oil company Petroecuador's exploration contracting unit – became the state oil company chief. The result was an optimistic policy document – 'Apertura Petrolera 2000' – which forecast that, with substantial foreign investment, the Ecuadorian oil industry would grow 11% annually until 2005, while oil's share of GDP would rise from 13% to 18%.

The hoped-for foreign investment was slated for the following:

- Joint ventures in field reactivation including the country's largest fields. Sacha, Shushufindi, Auca, Libertador and Cononaco which are currently operated by Petroecuador. In addition, foreign investment would be sought for the estimated 1.3bn barrels (in place) of heavy oil reserves which are at the Ishpingo-Tambacocha-Tiputini (ITT) fields in the eastern Oriente, which have failed to attract any foreign investment to date. National oil production fell an average of 73,000 b/d since 1994 to 374,048 b/d in late 1999, largely due to Petroecuador's inability to invest in boosting output.
- The construction of an oil pipeline to transport heavy crudes from the Oriente, the eastern jungle region, to the Pacific coast. Known as Oleoducto de Crudos Pesados (OCP) the pipeline is expected to cost an estimated \$500mn. It is to be operated for a period of 20 years by the private sector Oriente oil producers Repsol-YPF, Kerr McGee, Alberta Energy, Agip and Occidental, and built by a consortium comprising Williams Engineering and Techint of Argentina. Chase Manhattan Bank will arrange financing for the pipeline, if the project is deemed profitable, on a build-operate-transfer (BOT) basis.
- Private investment involvement in the Esmeraldas (90,000 b/d capacity) and La Libertad (40,000 b/d) refineries.
- A 10th exploration round to award 11 blocks in the Oriente Basin and three offshore blocks in the Gulf of Guayaquil.

In addition, the priorities over the next one and a half years were to request a \$850mn loan from the

World Bank to cover the state's obligations in energy projects – estimated at $1.5bn over the period – and to hire an investment bank to promote foreign investment in energy projects. Petroecuador would be reformed to limit its role in the oil sector to just four areas: environment, safety and security, consumer protection and monopoly regulation. The company's marketing and trading activities would be privatised.

This wish-list requires a reform of existing hydrocarbons legislation, both to specify precisely the state's minimum take of 40% in field reactivation projects, including all taxes and royalties, and to abolish VAT on oil transportation costs through the future OCP pipeline.

Stumbling block

But the main stumbling block has always been Ecuador's endemic lack of national consensus on oil sector reform. An expansion of the existing trans-Ecuadorian oil pipeline – Sistema de Oleoducto Transecuatoriano (SOTE) – from its current throughput capacity of 390,000 b/d to 420,000 b/d, has been delayed for several years largely because of opposition from Petroecuador's powerful trade union, Fetrapec, and other vested interests which did not approve of private sector investment.

The Army's corps of engineers have also pushed to be project managers of the expansion, rather than awarding it to a foreign contractor. The Ecuadorian armed forces receive approximately 10% of state oil company Petroecuador's export revenues for their own funds.

In addition, organisations which group together Ecuador's numerous indigenous tribes – including the largest, Confederacion de Nacionalidades Indigenas del Ecuador (Conaie) – are demanding a share of oil profits from production in their traditional regions.

As in other Latin American countries, such as Colombia and Bolivia, the Ecuadorian Government has always maintained a centralised hold on oil export revenues rather than devolving these to regions. But local communities have been quick to take advantage of provisions in the 1998 constitution which gives local communities the right to veto any oil (or mining or forestry) operations on their land and a right to examine all the technology that companies use and to approve that technology. In addition, every citizen has the right to be informed on impending oil operations that could affect his/her life and individuals have a right to oppose such operations.

In theory, anyone can stop the oil industry at will.

Deepening economic crisis

As the economic crisis deepened, so the protests from civic and indigenous groups accelerated. The greatest outrage was reserved for President Mahuad, alleged to have used public funds to bail out private banks, bankrupted by their owners' incompetence and embezzlement. As allegations of kickbacks abounded, unions and social groups joined with Conaie to call for the removal of President Mahuad, the closure of the Unicameral Congress and the resignation of the Supreme Court. The legislature would be replaced with a series of 'peoples' parliaments' and a government of national unity, that included the military.

As chaos ensued, President Mahuad declared a state of emergency on 6 January 2000, the dollarisation of the economy and the resignation of the Government on 9 January.

The dollar link-up is expected to cut inflation and interest rates, currently set at over 80%. In declaring the link-up to the dollar, President Mahuad overrode the Central Bank's statutory autonomy. The Central Bank directors opposed the dollarisation and resigned on 10 January. Had they not resigned Mahuad could have asked Congress to vote them out of office, but this would have needed a two-thirds majority in Congress.

As part of a strategy to find this majority Mahuad's party, Democracia Popular (DP) forged an alliance in the congress with the Partido Roldossista Ecuadoriano (PRE), a party founded by and led from a Panamanian exile by former President Abdala Bucaram. Bucaram was dismissed as President in February 1997 by the legislature for 'mental incompetence' following massive popular protests against his corrupt administration.

The DP-PRE alliance has displeased the armed forces, which had a hidden hand in the removal of Buckram, and outraged both the other political parties and the various social and indigenous groups who vow to continue with their protests.

Mahuad, a former Mayor of Quito, has even lost the support of the Quito business community after it became know that he had tried to negotiate a deal with the military which would enable him to shut down the congress. The military declined Mahuad's suggestion, instructed the civilian politicians to sort out the situation by themselves, but are not rushing to rescue Mahuad from his troubles. In a communique dated 8 Janaury the armed forces made little effort to give Mahuad a ringing endorsement stating: 'The President is President of the Republic, naturally while he remains President he has the total support of the armed forces.'

But by 10 January other centre and right-leaning parties had expressed support for Mahuad and their intention to vote for the dollarisation programme and attendant economic reforms. This has opened the way for further Congressional votes on amending hydrocarbon legislation.

The government intends to present this reform to the congress in the form of an 'urgent' bill that, if the Congress does not reject entirely within 15 days, automatically becomes law. The bill includes provisions for clarifying taxes on joint ventures in field reactivation and oil transportation, as well as further privatisations in the energy sector.

But all this depends on how long Mahuad can survive in office. A broad civic alliance including indigenous groups, social organisations, unions and small businesses are intent on continuing their street protests. A national consensus on oil and economic reform is unlikely given the increasing political instability.

Looking ahead

Quito pundits suggest that if Mahuad stays in the Presidency through mid-January he may be removed in March when his one-year freeze on dollar-denominated certificates of deposit expires. These deposits were frozen in March 1999 in an attempt to halt capital flight as the economic situation deteriorated. Oil sector reform will be stalled, they say, but not totally.

The constitutional replacement would be Vice-President Gustavo Noboa, who it is believed will retain Javier Espinosa as Economy Secretary and thus maintain an all-important political clout to make the oil industry attractive to foreign investors.

The construction of the heavy crude oil pipeline, field reactivation joint ventures and the 10th exploration round will probably go ahead. But further privatisation of the refining sector, reform of Petroecuador and any privatisation in the electricity sector are fiercely opposed by the left wing political parties and various trade unions and social groups, and will probably be delayed yet again.

MTBE – How should Europe respond ?

Most oil companies will be aware of the decision by the State of California to phase out the use of MTBE (methyl tertiary butyl ether). Key questions now are what does this mean for Europe and how should European oil companies respond? The following is Shell's view on possible ways forward for the industry.

The decision by the State of California to phase out MTBE was made not on health grounds, but because of the taste and odour impact it can have on groundwater in the event of accidental spills. The question for Europe is whether the benefits of continuing to use MTBE in gasoline outweigh the risk of similar impacts on water resources, or whether a phase-out, as seems possible throughout the US, is justified.

Shell's view is that the oil industry needs to address these issues but cannot do so alone – not least because no short-term alternative appears to be acceptable to all parties. Shell believes that a constructive dialogue is therefore required between the key parties concerned to determine the best way forward. Adrian Loader, President of Shell Oil Products Europe, has recently written to the other oil companies in Europe, through the European Petroleum Industry Association, urging them to come together to address the MTBE issue.

What are the issues?

The principal public concern is the contamination of groundwater, particularly where it is used for drinking water supplies. Small amounts of MTBE are able to taint large volumes of water – a single spirit measure (30 ml) in a large swimming pool (500 m^3) is around the taste and odour threshold.

MTBE is used throughout Europe to boost octane rating in fuels, especially in super unleaded and lead-replacement grades. It will be used in increased amounts because the new EU fuels legislation which came into effect on 1 January 2000 requires that benzene, aromatics and olefin contents of gasoline fall to lower levels and that leaded gasoline is phased-out (see *Petroleum Review*, September 1999).

MTBE is a volatile, water-soluble, oxygen-containing, colourless liquid with an ethereal odour. Although it has been added to gasoline for some years, public awareness over its use emerged when reformulated gasoline became mandatory over large areas of the US in a bid to reduce vehicle exhaust emissions of carbon monoxide. MTBE has since been found in drinking water supplies and in groundwater wells. This, together with the contamination of Lake Tahoe (a drinking water resource) by unburned two-stroke fuel from boat and 'jet-ski' exhausts, led the Governor of California to call for the phase-out of MTBE use. These concerns have been largely supported by a Blue Ribbon Panel set up by the US Environmental Protection Agency (EPA).

Really no health risk?

Extensive studies have been carried out to determine the health effects of MTBE. A review of these studies (CONCAWE report no. 97/54) concludes that 'MTBE has a low order of acute toxicity, and is not teratogenic, mutagenic, neurotoxic, nor a reproductive toxicant.' Subsequently, the International Agency for Research on Cancer (IARC – part of the World Health Organisation) reviewed the carcinogenicity data on MTBE and decided that there was a lack of evidence to justify any classification as a human carcinogen and that this view would be reconsidered only if significant new data became available.

In December 1997, the US EPA Office of Water published *Drinking Water Advisory: Consumer Acceptability Advice and Health Effects Analysis on MTBE*, which recommended that MTBE concentrations less than 20 µg/l to 40 µg/l (ppb) would not normally give rise to unpleasant taste and odour effects for a large majority of people. It also concluded that there is little likelihood that these MTBE concentrations would cause adverse health effects because they are tens of thousands of times lower than the range of exposure levels that caused observable health effects in animals.*

Water contamination concern

The most common ways in which MTBE enters the environment are by accidental releases of gasoline containing MTBE and use of gasoline two-stroke-powered watercraft. Two-stroke engines emit unburned fuel from their exhausts, which in the case of watercraft results in MTBE dissolving in the water. Accidental spills could occur at any stage of the manufacturing/distribution system. This includes leaks from underground storage tanks at retail sites, operations at distribution terminals, and product pipelines.

As MTBE is volatile, some will evaporate into the atmosphere during distribution and use. Small amounts are also emitted from four-stroke vehicle exhausts. Any MTBE emitted degrades in the air, so concentrations in the atmosphere remain low. However, because of its solubility in water, some MTBE will be washed out by rain and enter surface and shallow ground waters. As a result, MTBE can often be detected in shallow ground waters at concentrations of less than 1 µg/l.

At filling stations standards for storage tanks, site design, and leak monitoring continue to improve, with many sites rebuilt in recent years. Double-skinned tanks, leak detection, leak-proof pavements and reconciliation of volumes are being used to improve containment and monitor for leaks. However, total containment is unlikely to be achievable.

The volumes of MTBE that could give rise to problems are very small and MTBE is much more soluble in water (43 g/l) than gasoline hydrocarbons (benzene at 1.8 g/l is one of the most soluble). It biodegrades only slowly – and perhaps not at all in the absence of air – and is only weakly adsorbed on soil particles. MTBE therefore tends to persist in groundwater, to travel further and faster through the ground than hydrocarbons, and is likely to be present in higher concentrations.

Although MTBE is resistant to biodegradation, it does slowly degrade given sufficient air, nutrients and suitable bacteria. In an eight-year field-experiment, 90% disappeared. If necessary, naturally-isolated bacteria can be grown in the laboratory and introduced to the contaminated site or used in a biotreater. Thus, given the appropriate conditions MTBE can be degraded. Biodegradation in the absence of air, however, has not been confirmed. Many authorities now accept natural remediation of spills and leaks of gasoline containing the aromatics benzene, toluene, ethylbenzene and xylene (BTEX) as appropriate, but not yet for MTBE-containing gasoline.

Alternatives to MTBE

Lead and some other metals are the most effective octane enhancers. However, lead is in the final stages of being phased out because of environmental and health issues, and the most readily available alternative, MMT (Methylcyclopentadienyl Manganese Tricarbonyl), is currently not widely accepted.

The octane loss from lead removal has been made up by refinery processing changes which produce higher octane gasoline blending components – in some cases (for example, reformate). These components increase the aromatic content. This is a significant constraint, since permitted levels of aromatics are being lowered to help reduce the impact of vehicle exhaust emissions on air quality. Additional capacity for low-aromatic, high-octane hydrocarbon components would require considerable investment and take time to come onstream.

The only other octane enhancers currently available are MTBE and other ethers, such as ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), or alcohols such as ethanol. The ethers have similar properties and drawbacks. Ethanol is already used as a gasoline blending component in parts of the US, where it is readily available and in Brazil. It is an effective octane booster, but has a number of drawbacks: it needs a 'water-free' distribution system, and is not without groundwater issues. It is not recommended by the motor industry and is not cost-competitive.

How should Europe proceed?

In his letter, Adrian Loader said: 'I think that time is starting to run out on this issue and that it would be wise for the industry to get actively involved in managing the issue. Given the developments in the US, we must act responsibly to assess and address the possible risks and stakeholder concerns in Europe.'

Shell believes that a constructive dialogue is required between the key parties in order to determine the best way forward. The aim should be to ensure a full understanding of the complexities of the issue and to seek practical solutions which balance off possible risks, benefits and costs. An industry-wide approach is necessary because even if individual manufacturers stop using MTBE in refineries, exchange product they receive from other suppliers may contain MTBE, and fuels carried by common pipelines or supplied from shared depots may be contaminated with traces of MTBE.

Constructive dialogue by the industry with relevant bodies, such as health and regulatory bodies, the motor and water industries, motorist representatives and probably NGOs (non-government organisations) etc. will be required. As the alternatives to MTBE may involve potential risk, or are legislatively constrained, Shell believes that it is important to consider their full implications.

Concerns about MTBE are already emerging in Europe, and the European Commission has called for data from national governments on groundwater concentrations. In the UK, the Environment Agency and the Institute of Petroleum have just commissioned a study to gather data from water utilities and gasoline retailers on MTBE concentrations in groundwater. In Denmark, wells near filling stations must be tested for MTBE.

In California, a timetable has been set for MTBE phase-out to give companies the time to deal with the major implications of its withdrawal. In Europe, in the short-term, it is not possible to phase out the use of MTBE in manufacturing gasoline because of the lack of alternatives and legislative constraints – especially since MTBE is the preferred component to meet the legislated reduction in aromatics and the lead ban from January 2000.

Possible solutions?

A phase-out of MTBE may eventually be the way forward for the oil industry. This might be achieved:

- through limitations on use (for example, phase-out of high octane grades)
- a relaxation of the aromatics specification requirements if no MTBE is present
- alternative high octane streams (for example, other non-ether oxygenates or hydrocarbons) or
- additive solutions (such as MMT)

Alternatively, society might accept the groundwater risks associated with the use of MTBE given that there are no proven health issues, in which case it might not be necessary for the industry to find an alternative.

However, as there are no immediate, widely-acceptable solutions, steps should be taken to identify and quantify specific options and risks. Public perceptions need to be taken into account by ensuring that credible HSE data is available and communicated. Given the developments in the US, Shell believes the oil industry must act responsibly to assess and address the possible risks and stakeholder concerns in Europe and other markets.

It is essential that the industry engages in a dialogue involving all stakeholders, to ensure that the public is reassured, that the options are explored objectively and realistically, and that the issue does not escalate into an unjustified crisis in Europe or elsewhere.

* Which include disputed cancer claims based on non-standard animal tests and partly published work.

New products for the Millennium

Two new oil 'Millennium Products' were recently announced by UK Prime Minister Tony Blair, which brings the number to 1,012 since the nationwide initiative on innovation was launched in 1997 in a bid to promote British products around the world.

FSM-IT (Field Signature Method Inspection Tool) from CorrOcean is a new portable system for monitoring and inspecting the internal condition of metallic pipes, pipelines and containers. Based on the established Field Signature Method engineering technique, the system measures the voltage drop between sensing pins placed externally on the metallic structure with the aim of detecting internal metal loss due to corrosion or erosion. It is claimed to be particularly suited to the remote monitoring of inaccessible areas such as buried or subsea pipelines and hazardous areas such as nuclear installations.

Slingsby Engineering's Olympian remotely operated vehicle is designed for carrying out difficult construction, repair and maintenance to subsea oil installations down to 3,000 metres in the roughest ocean conditions. It is said to be able to complete tasks at depths well beyond the capabilities of divers and other industry standard work class ROVs.

Further information on Millennium Products is available from Neil Cozens at the Design Council on +44 (0)20 7420 5273 or visit the Millennium Products website at **www.millennium-products.org.uk**

Helping refiners meet low sulfur level requirements

The need for ultra-low sulfur detection is growing as a result of increasingly stringent regulations governing the level of sulfur in petrol. In order to help refiners more accurately measure sulfur levels in their products, CSP has developed the new Antek 9000LLS low-level sulfur analyser.

'Trace measurement of sulfur has always been tricky, with available instrumentation requiring highly trained and qualified staff,' comments CSP Product Manager, Steve Duffin. 'The new Antek instrument is stable and easy to run. The system is more robust than coulometric methods, more sensitive than X-ray, safer and faster than lead acetate.'

The analyser uses patented Pyrofluorescent™ sulfur analysis technology that is claimed to offer rapid, precise measurement of solid, liquid and gas samples. It provides determinations for an analytical range of low ppb to 40% within minutes, states CPS, without the use of environmentally hazardous catalysts or reagents.

The unit includes a data handling system with Windows™-based, custom-designed software that provides data acquisition, analysis and storage. Remote instrument operation and real-time analysis support are available via a pre-configured modem.

Tel: +44 (0)1708 476162
Fax: +44 (0)1708 707778

Alarm additions

MEDC has added the XB9 Xenon Beacon, SDI smoke detector and DB3/DB4 sounders and speakers to its product portfolio. All units are certified for use in Zone 1 and Zone 2 environments. The SD1 smoke detector (pictured) is said to be capable of detecting smoke over a 1,500 sq metre area, eliminating the need for a large number of smoke detection units.

Tel: +44 (0)1733 864100
Fax: +44 (0)1773 582820

Tank content control

Saab Tank Control has launched its new operator software – Saab TankMaster. Said to give the operator full control over inventory at tank plants, the software presents level, pressure as well as temperature readings, and computes density, mass and weight in real time. Calculations include gross and net volumes in compliance with API and other important industry standards.

The software, which is based on an open industry standard and eliminates the need for costly customised software integration, can also be connected to the Internet to obtain information on tank contents in real-time. Visual Basic programs enable log or product reports to be generated for each plant shift, every 24 hours or at other intervals specified by the operator. All reports can be sent by e-mail. Alarms can be sent to mobile telephones or pagers.

The system offers a number of measuring options. It can be used to monitor only those tanks where there are temporary fluctuations in level. Overfill level alarms can be selected for standard net volumes or a certain leakage level. The tanks being analysed can be organised geographically or by product, and can be divided into sub-groups.

All alarms are logged to provide a reliable follow-up service. Up to 10,000 readings per tank can be saved.

Tel: +46 31 337 07 05
Fax: +46 31 25 30 22

NEWS Technology

Integrated process control first from Honeywell

Honeywell Control Systems claims to have achieved an industry first with the introduction of PlantScape® Distributed Server Architecture as part of its PlantScape Release 300. The technology is said to launch the next generation of process control by allowing multiple PlantScape systems to operate as one integrated system – plant-wide or across the world – without any duplication of engineering effort.

'Distributed Server Architecture is the ideal solution for integrating processes when there are multiple control rooms, or for segmenting control across units, providing the ultimate flexibility for both operations and control,' states the company. 'It also provides the maximum flexibility for geographically distributed sites. For example, it allows multi-segment pipelines and oil and gas fields with a large number of wells to be managed from multiple remote locations as well as a central control room. Prior to the development of Distributed Server Architecture, the integration of multiple processes and applications required significant non-value added engineering costs, duplication of databases, non-integrating alarming, and gateway technology resulting in communication bottlenecks.'

Tel: +44 (0)1344 656000
Fax: +44 (0)1344 656240

Fishsafe funding

Production of an electronic safety device which has been designed to reduce the risk of North Sea fishermen's nets becoming caught on pipelines, wellheads and other underwater obstacles has been given the green light following the award of European and oil industry funding. The grants, totalling £345,000, will subsidise the production of 300 of the FishSafe devices, effectively cutting the final cost to fishermen by over two-thirds to around £500. The safety device will be made available from March 2000.

The UK Offshore Operators Association (UKOOA) is contributing £200,000 to the safety initiative, while the European Commission's PESCA programme (which is being coordinated by Aberdeenshire Council) is contributing £120,000. The Scottish Fishermans Federation (SFF) is providing a further £25,000.

A record of all known subsea obstacles in UK waters is currently being completed by Seafish in conjunction with the existing electronic navigation systems already employed at sea, to guide fishermen away from underwater structures as well as exclusion zones around subsea facilities such as wellheads and pipelines. The obstacles are displayed on the FishSafe screen which is installed in the wheelhouse. If a fishing vessel strays within a six-mile radius of any such obstacle, audio and visual alarms are triggered which increase in intensity the closer the obstacle gets.

Tel: +44 (0)1224 257500
Fax: +44 (0)1224 257523

Low-flow pump protection

Narvik-Yarway, part of the Tyco Engineered Products Group, has extended its Series 9200 range of automatic recirculation control valves (ARC) to include larger sizes. The ARC range is designed to provide a high level of protection for centrifugal pumps against the damage of overheating caused by low flows.

Completely self contained, the Series 9200 is an integrated system which functions as a flow sensing device, spring-loaded check valve, recirculation control valve and staged pressure let-down device. This single system is claimed to provide 'considerable cost savings and energy savings over the more traditional and complex multi-instrument flow control loops.'

The Series is available in a range of sizes, from 2- to 4-inches, and pressure classes ANSI 150 to 300.

Tel: +44 (0)1722 415588
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If you would like your new product releases to be considered for our Technology News pages, please send the relevant information and pictures to:

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Alan Chamberlain (right) Chairman of the IP Petroleum Measurement Committee presents Captain Nick Gikas (left) with the IP's Certificate of Appreciation for his work on Marine Loss Control. Nick who works for Mobil Sales and Supply was Chairman of the Marine Loss Control Sub-Committee from 1991 to 1996. He is still an active member of the IP Loss Control Sub-Committees regularly attending both the Marine Loss Control and Cargo Inspection Sub-Committee meetings

John Phipps (left) presents Dr Bryan Hayton (right) with the IP's Certificate of Appreciation for his work on Bitumen. Bryan, who worked for Shell Research and Colas before setting up Longroyd Associates, has been associated with the IP since 1976. He was Chairman of the Bitumen Committee from 1994 to 1998 and Chairman of the Bitumen Emulsion Panel from 1976 until 1998.

Addendum to Awards

Please note that recent IP Certificate of Appreciation winner Eddy Murray's biography as reported in the October issue of Petroleum Review should have stated that he was a Principal Signatory for Esso at Abingdon.

New Year Honours for the Year 2000

A number of oil and gas industry personnel have been awarded New Year Honours. **Ian Robinson,** Chief Executive, Scottish Power has been Knighted for his services to the electricity industry, while **Malcolm Kennedy**, Chairman, BP Power, was awarded a CBE for services to export. **George Watkins**, Chairman and Managing Director of Conoco was also awarded a CBE and **Caroline Harper** an OBE for her services to the gas industry. **Andrew Owens** of Greenergy was awarded an MBE as was **Elizabeth Rhodes,** Director of the Shell Technology Enterprise Programme.

Recruitment

Newly Published TC 67 Standards

As reported in last month's *Petroleum Review*, the end of 1999 saw five more International Standards for the materials and equipment for the petroleum and natural gas industries published. The following text has been prepared on ISO 14691 'P&NGI – Flexible couplings for mechanical power transmission – General purpose applications' by the ISO/TC 67/SC 6/WG 9 Convenor, and ISO Project Leader for this standard, Peter Simmons.

ISO 14691 Petroleum and natural gas industries – Flexible couplings for mechanical power transmission – general purpose applications

All those involved in the development of ISO/TC 67 standards for the petroleum and natural gas industries, are pleased to announce the publication of the above International Standard. This will now follow the 'Unique Acceptance Procedure' within CEN/TC 12 and will hopefully be available to purchase as BS EN ISO 14691 shortly. The drafting work has been carried out by Working Group 9 of ISO Technical Committee 67, Sub-committee 6, "Processing equipment and systems". The Institute has played an active role in the development of this standard, supporting the UK Project Leader and co-ordinating the wider UK input.

The subject standard is a companion standard to BS EN ISO 10441 'Petroleum and natural gas industries – Flexible couplings for mechanical power transmission –Special purpose applications', which is based on API Std 671.

ISO 14691 has been developed to satisfy a need for a coupling standard for pumps, fans and small compressors, where the rigour of a fully engineered coupling in accordance with ISO 10441 is not considered necessary, and would therefore add considerable cost. There is currently no other comparable internationally accepted standard.

The purchaser is of course always free not to invoke a standard at all. However, without an effective technical standard, if the selection of a coupling is left entirely to the machine supplier, commercial pressures in the market place can result in a coupling being supplied which may fail in service, with potentially disastrous results, from both safety and economic considerations.

For the above reasons it is recommended that users of rotating machinery specify couplings to be supplied in accordance with ISO 10441 or ISO 14691 as appropriate, except for very small machines in non-critical services.

TC 67 Progress in 2000

Already this year four Final Draft International Standards (FDISs) have been issued by ISO Central Secretariat for voting by ISO/TC 67. The FDIS is the final stage in the development of an International Standard, and if TC 67 P-members approve the standard, publication can be expected within three months of the FDIS closing date. More details of newly published TC 67 International Standards will follow on this page throughout the course of what is hoped will be another successful year for the Technical Committee.

Funding for ISO Standards work

The Institute of Petroleum is to boost the development of international standards for the petroleum and natural gas industry. The budget proposal to allocate £100,000 of its company-members funding to UK efforts in progressing ISO/TC67 Standards, in the year 2000 was approved recently. The funding was agreed after six months of lobbying and preparation and there is a direct link with ISO/TC67 having a credible leadership and management system and the target of publishing 30 standards in 2000.

These funds are to assist UK experts to contribute to standards writing and for work items in which the UK has a particular interest. The push will be towards using the money to accelerate the publication of international standards to the benefit of the global petroleum industry. There will be a quarterly review of progress to meeting the ambitious publication target, so the pressure will be on all the UK participants to achieve progress.

The funding is similar to that provided by CRINE Network in conjunction with the DTI/IEP which totalled £250,000 over the period 1998-1999. The government has assigned the CRINE Network contract to the Institute, which will now coordinate all the UK input to ISO/TC 67. The balance of the CRINE Network funds has also been transferred. The total available to spend, with the other subsidies from the government and industry, will be close to £200,000.

We invite you to join the challenge, to match our efforts and help ISO/TC 67 meet its delivery expectations. Assigning most of the IP funds is the responsibility of the BSI/UK mirror committee PSE/17 and proposals will be approved by its Chairman. If you have any ideas about work which might benefit from funding assistance, please let us know. For further information contact Sjoerd Schuyleman by phoning 0171 467 7132 or send an e-mail to **sfs@petroleum.co.uk**

In addition, the Institute is a participant in the International Association of Oil and Gas Producers (formerly E&P Forum) which has a £40,000 joint industry fund to pay for technical editing and formatting of the ISO/TC67 Standards in 2000. It is not our intention to duplicate that effort and close contact will be maintained.

IP 334/93 Determination of load carrying capacity of lubricants FZG gear machine method

As IP 334/93 no longer meets the requirements of the present day oil industry, the IP's Lubricants, Greases and Waxes Test Methods Sub-committee (IP ST-C) has agreed that it will be withdrawn from the IP Standard Methods Book with effect from 2001. Users wishing to determine the load carrying capacity for transmission lubricants are recommended to use the technically equivalent CEC method, L-07-A-095 *Load Carrying Capacity Test for Transmission Lubricants.*

Copies of this method can be obtained from CEC: Madou Plaza, B-1030 Brussels, Belgium.

Tel: +33 22 23 19 30 Fax: +33 22 26 19 39

Our website can be found @ www.petroleum.co.uk/tech/stds

NEW Publications and Data Services

Lloyd's Survey Handbook

Norman Millard (LLP Ltd, Sheepen Place, Colchester CO3 3LP, UK). ISBN 1 85978 682 0. 370 pages. Price (hardback): £58 ($99).

Now in its seventh edition, this handbook provides a comprehensive and practical guide to cargo handling. Written by Norman Millard, President of the British Association of Cargo Surveyors, it covers a wide range of cargoes carried by sea, as well as those transported by air and land. It provides best practice general information on surveying techniques and a list of over 600 commodities with details of their specific propensities, method of packing and potential problems in carriage. Thoroughly revised and updated, this latest edition includes a new chapter on loss prevention and information on the safe working in confined spaces.

Project Management: Explanatory English–Russian Dictionary

Editor: Prof. Valery Shapiro (Smith Rea Energy Analysts, Publications Department, Hunstead House, Nickle, Chartham, Canterbury, Kent CT4 7PL, UK). ISBN 5 06 003671 5. Price: £100 (UK); $175 (overseas).

This new dictionary describes various English language project management terms in Russian terminology and Cyrillic script. The book is aimed at project managers, and others, dealing with major capital investment projects in Russia and countries where Russian is the *lingua franca*. Many of the terms defined are also commonly used in other business areas, and the work is thus of wider interest. The book also includes a brief Russian–English dictionary of foundation terms.

European Downstream Oil Industry Safety Performance*

(Available, free of charge, from CONCAWE, Madouplein 1, 1210 Brussels, Belgium). 15 pages.

This report (no. 9/99) reviews the safety performance of the downstream oil industry in Europe during 1998. It includes the results of 27 companies which together represent over 90% of the oil refining capacity in the region. The data for 1998 is compared with the averages for the five-year period 1993–97. Overall, the reported hours worked by company staff and contractors combined were about 470mn with an average lost workday injury frequency of 4.5. This is very similar to figures reported in previous years which ranged from 4 to 4.7, and with the average for the five-year period of 4.5. A range of other measures of safety performance are also reported.

Signal Processing for Geologists & Geophysicists

Jean-Luc Mari, Francois Glangeaud and Francoise Coppens (Éditions Technip, 27, rue Ginoux, 75737 Paris Cedex 15, France). ISBN 2 7108 0752 1. 480 pages. Price: FFr 520 (euro 79.27).

The aim of this book is to familiarise geologists and geophysicists with the basic concepts of signal processing used in seismic surveys. It shows the value of using a combination of tools to solve a given problem, with many of the examples coming from the latest research. A French/English CD-ROM, entitled *Signal Processing in Geosciences*, has also been produced, based on the book. It features 86 animations with adjustable parameters which present the various tools and concepts used in signal processing, their limits and necessary precautions, as well as numerous applications.

* *Held in IP Library*

Production-Sharing Agreements: An Economic Analysis*

Kirsten Bindemann(Oxford Institute for Energy Studies, 57 Woodstock Road, Oxford OX2 6FA, UK). ISBN 0 901795 15 2. 93 pages. Price: £50.

Production sharing agreements (PSAs) are among the most common types of contractual arrangements for petroleum exploration and development. The study looks at the balance between risks and rewards, and the division of benefits among the parties to the contract which have not yet been analysed with the tools of modern industrial economics. Some simulations are introduced to highlight the sensitivity of the contract parameters to changes in endogenous (for example, changes in the shares of cost oil and/or profit oil) and exogenous (such as oil price change) variables. The role of national oil companies is evaluated with regard to both their relationships with government and interactions with foreign contractors. The study's empirical analysis is based on a data set comprising 268 PSAs signed by 74 countries between 1966 and 1998.

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Fax any of the above on +44 (0)20 7255 1472 or e-mail **lis@petroleum.co.uk** Visit our website at **www.petroleum.co.uk**

Membership News

NEW MEMBERS

Mr T Baker, Shaw and Croft
Mr S R Bauerband, Mobil Oil Corporation
Mr J Brinkhurst, London Fire & Civil Defence Authority
Mr J Brueckner, Morgan Stanley Dean Witter
Mr D J Denton, Lowestoft
Mr O A Eguando, SGS Inspection Services Limited
Mr M A Eju, Nigeria Liquefied Natural Gas Limited
Mr B G Ewen, Maritime Claims & Services Pte
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Mr D German, Bristol
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Mr B E Okon, Nigeria
Dr N R Popat, London
Mohd S H Radzuan, Bolton
Mr P Skyes, Cleckheaton
Ms J W T Tan, London
Mr M B Thomson, Offshore Technology Management Limited
Mr M A Tosdevin, OMV (UK) Limited
Captain A M Wallace, Plymouth
Mr T Waterfield, FPD Savills

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Mr J A Cooke, Newcastle-under-Lyme
Mr L R Diaz Teran Ortegon, Mexico City
Mr C Gunn, London
Mr M Z Jaafar, Imperial College
Ms R Manilerd, London
Ms S L Mumford, London
Mr J M Muruais, London
Mr E-O I Obi, London
Mr T G Ovington, Imperial College
Mr H Sadrpanah, London
Mr L Shakarji, London
Mr K Watanabe, Imperial College

STUDENT PRIZEWINNER

Mr F Beltrami, Italy

NEW CORPORATES

Exchange Consulting Group Ltd, 13 St Swithin's Lane, London EC4N 8AL, UK
Tel: +44 (0)20 7929 2383 Fax: +44 (0)20 7929 2805
Representative: Trish Collins, Managing Director
They are a specialist recruitment consultancy supplying trading, broking, traffic, risk management, trade finance, settlement, accounting and compliance professionals to all types of participants in the international oil and power trading and broking community.

GOLDEN ANNIVERSARIES

The IP is proud to announce that the following Members have all been award a special commemorative tie as a result of achieving 50 years of Membership: Mr M E Astrup FInst Pet, Mr J G Larcombe FInst Pet, Sir Louis Le Bailly KBE CB DL FInst Pet, Mr G A Lee FInst Pet, Mr E H Sadler FInst Pet, Mr W E Sumner-Andrews FInst Pet, Mr B H Watts FInst Pet

IP Discussion Groups & Events

Energy, Economics, Environment

'Drilling for Oil on Wall Street – An Alternative Exploration Strategy'

Thursday 9 March, 17.00 for 17.30

Dr Rob Arnott, Morgan Stanley Dean Witter

IP Contact: Jenny Sandrock

Energy, Economics, Environment

'Sanctions – The Political Limitations for E&P'

Thursday 30 March, 17.00 for 17.30

Charles Gurdon, Managing Director, Menas Associates

IP Contact: Jenny Sandrock

London Branch

'16th World Petroleum Congress: Why You Should Be There!'

Tuesday 15 February

Jim Gray, Chairman, Canadian National Organizing Committee, WPC

Contact: Carol Reader Tel: +44 (0)20 8852 9168

Please note the change of date which was advertised incorrectly in the January issue of *Petroleum Review*. Our apologies for any inconvenience caused.

Energy, Economics, Environment Discussion Groups

Please notify the contacts if you plan to attend any of the advertised events

All events will take place at the IP unless stated otherwise

Institute of Petroleum
61 New Cavendish Street
London W1M 8AR, UK
Tel: +44 (0)20 7467 7100
Fax: +44 (0)20 7255 1472
e: jsandrock@petroleum.co.uk

IP THE INSTITUTE OF PETROLEUM

Branch Activities

Aberdeen
Contact: *George Wood Tel: +44 (0)1224 205736*
8 February: Annual General Meeting
14 March: Future UKASE Activity Levels, by Prof Alex Kemp of Aberdeen University

East Anglia
Contact: *Brian Holloway Tel: +44 (0)1953 601312*
23 February: AGM, and Road Tanker Construction, by Graham Holiday

Essex
Contact: *Arnold Carlson Tel: +44 (0)1268 794615*
9 February: AGM, and Energy Trends for the Millennium, by Tamar Earley of Greenergy
8 March: The Future of Packaging by Ian Robinson of IK Robinson Associates, P Peuch of BP Chemicals, and Tony Hancock of Plysu Containers
17 March: Annual Dinner and Dance

Humber
Contact: *David Hughes Tel: +44 (0)1469 555237*
3 February: AGM, and Simon Storage Killingholme Project
3 March: Annual Dinner

London
Contact: *Carol Reader Tel: +44 (0)20 8852 9168*
15 February: 16th World Petroleum Congress: Why You Should be There! by Jim Gray, Chairman, Canadian National Organising Committee, WPC

Midlands
Contact: *Margaret Ward Tel: +44 (0)1299 896654*
23 February: Factory visit, AGM and technical paper on petroleum road tankers

North East
Contact: *John Sparke Tel: +44 (0)1642 546411*
1 February: AGM, and Transport and the Environment, by Martin Maeso, IP Environment Manager
21 March: Visit to Northumbrian Water Ltd. Bran Sands Treatment Plant

Northern
Contact: *Alan Holt Tel: +44 (0)161 875 3242*
29 February: AGM and social event
28 March: Grease, by a speaker from Axiel Christienson

South Wales
Contact: *Steve Vines Tel: +44 (0)1646 600679*
25 February: AGM, and The Story of Pembrokeshire Wine, by John Hamilton-Cowburn
14 March: *Sea Empress* Follow-Up, by Robin Crump at Elf Refinery, Milford Haven
24–26 March Weekend in Hereford

Stanlow
Contact: *John Wellsteed Tel: +44 (0)151 479 4962*
10 February: Fuelling the Armed Forces on Active Service, by Capt. McIlveen, The Royal Engineers
9 March: Calibration and Measurement of Storage Tanks, by John Miles of SGS

West of Scotland
Contact: *Allan Lawson Tel: +44 (0)1738 456701*
9 March: The Petroleum Dinner, Glasgow

Yorkshire
Contact: *Ivor Bennett Tel: +44 (0)1484 713201*
8 February: AGM, and hotpot supper with guest speaker John Morgan, *Yorkshire Post* sports journalist
14 March: Vauxhall V6 Engine, by Ken Davies of Vauxhall Motors. (Joint meeting with The Institute of Energy)

IP Conferences and Exhibitions

European Conference on

Transport 2000 and Beyond – Alternative Fuels in the 21st Century

London: 23–24 March 2000

- New improved engine technologies
- The development of 'cleaner' fuels
- Using gas and gas-derived products
- Daimler-Chrysler's commercially available fuel cell car in 2003.

These are just some of the developments that indicate the timeliness of this IP European Conference organised in association with AFTP (F), DGMK (D), CEP (E), RBPI (B) and ECN (NL).

Bringing together government and supranational authorities, suppliers of fuels and both fuel and engine technologies, evaluating the pace and direction of the development of transport fuels, this important European Conference will also consider how choices are made and the levers that can be used to direct public policy. These factors will dictate the strategic future of transport fuels and be of interest to suppliers of fuel, technologies and equipment, motor manufacturers, their customers and others interested in transport policy.

The programme and registration form is now available.

International Conference on

'Digital Black Gold' – E-commerce in the Oil and Gas industry

London: 11 April 2000

'E commerce has saved the corporation $1bn'
Jack Welch CEO of General Electric

Maybe you buy books from **amazon.com** or groceries from Tesco on the Net but how does this relate to making the oil and gas industry more efficient, cost effective and competitive in managing the supply and customer chain?

The IP Conference 'Digital Black Gold' brings together experience from other industries, the facilities and services available from specialist Internet companies, analysis of financial and legal obstacles and initial findings of energy companies.

This conference is not aimed at IT specialists but rather at managers who need to understand the implications of e-commerce for their business and may have a part to play in implementing e-commerce strategies.

Sir John Browne has said that 95% of BP Amoco's supply chain management will be via the Internet by the end of 2000! Perhaps you should be there!

The programme and registration form is now available.

International Conference on

INTERSPILL 2000

Brighton, UK
28–30 November 2000

A major conference and exhibition featuring the activities of the European spill response industry, both at sea and on land, under the direction of the **British Oil Spill Control Association** and organised by the **Institute of Petroleum**. It is planned that **INTERSPILL 2000** will be the first in a regular series of such events.

Topics to be covered

The topics to be discussed during the conference sessions, and through the exhibition and its associated poster presentations, will include:

- the nature of the response problem in all its aspects;
- the avoidance of secondary releases in marine casualty situations and the implications for response provision;
- the influence of shoreline and inland characteristics, and the different response requirements for water and solid surfaces;
- the strengths and weaknesses of available techniques and equipment in respect of operational factors;
- waste disposal options and the impact of regulations on option choice, storage, handling, and transportation;
- the limited capacities of authorised waste disposal facilities, and the consequent need for ways of minimising the amount of waste arising from pollutant clearance operations;
- the means by which pollution response can be improved through the pooling of all available expertise and resources within governments and the private sector; and the scope for further innovation in equipment, techniques, and operational planning.

Who should attend?

INTERSPILL 2000 will be of interest to all who are concerned about the environment and involved in its protection, including:

- national and international environmental agencies;
- oil, chemical, and transport industries;
- port and harbour authorities, and offshore oil field operators;
- central and local authorities, and emergency services.

The programme and registration form will be available in March.

A Trade Exhibition will accompany this event.

To add your details to the mailing lists, please contact:

Pauline Ashby, Conference Department, Institute of Petroleum,
61 New Cavendish Street, London W1M 8AR, UK
Tel: +44 (0)20 7467 7100 Fax: +44 (0)20 7255 1472 e: **pashby@petroleum.co.uk**

or view the IP Web Page: *www.petroleum.co.uk*

EVENTS Forthcoming

FEBRUARY 2000

9–10 **London**
3rd Annual E&P Data Management in Oil & Gas
Details: SMi Customer Services, UK
Tel: +44 (0)20 7252 2222
Fax: +44 (0)20 7252 2272

IP Week: 14 February
London: *Oil and Gas: An Industry Fit for the Millennium*
Details: Pauline Ashby, The Institute of Petroleum

11–14 **Surrey, UK**
Understanding Oil Supply Logistics
Details: Petroleum Economist, UK
Tel: +44 (0)20 7831 5588
Fax: +44 (0)20 7831 4567/5313
e: jackets@petroleum-economist.com

14–15 **London**
Gas-to-Liquids Conference
Details: IBC Global Conferences Ltd, UK
Tel: +44 (0)20 7 453 5491
Fax: +44 (0)20 7636 6858
e: cust.serv@ibcuk.co.uk

IP Week: 15 February
London: *Restructuring of the Energy Industry*
Details: Pauline Ashby, The Institute of Petroleum

16–19 **Pattaya, Thailand**
Oil & Gas Thailand 2000
Details: Heather Edkins, Overseas Exhibition Services Ltd, UK
Tel: +44 (0)20 7862 2073
Fax: +44 (0)20 7862 2078
e: hedkins@montnet.com

IP Week: 16 February
London: *13th Oil Price Seminar and Exhibition on Coping with Volatility – Futures and Derivatives for the Oil Markets*
Details: Pauline Ashby, The Institute of Petroleum

16 **London**
A New Era in North African Oil & Gas Development
Details: British Institute of Energy Economics
Tel: +44 (0)20 8997 3707
Fax: +44 (0)20 8566 7674
e: mailbox@biee.demon.co.uk

IP Week: 17 February
London: *The Middle East – The Key to Global Oil Supply*
Details: Pauline Ashby, The Institute of Petroleum

21 **London**
North Africa Oil & Gas Summit
Details: IBC Global Conferences Ltd, UK
Tel: +44 (0)20 7453 5491
Fax: +44 (0)20 7 636 6858
e: cust.serv@ibcuk.co.uk

22–23 **London**
North Africa Oil & Gas Summit
Details: IBC Global Conferences Ltd, UK
Tel: +44 (0)20 7453 5491
Fax: +44 (0)20 7636 6858
e: cust.serv@ibcuk.co.uk

23–24 **London**
Health Effects of Vehicle Emissions
Details: Energy Logistics International Ltd, UK
Tel: +44 (0)1628 671717
Fax: +44 (0)1628 671720
e: enquiries@energylogistics.co.uk

24–25 **London**
Combined Heat and Power Conference
Details: ICM Conferences Ltd
Tel: +44 (0)20 7436 5735
Fax: +44 (0)20 7436 5741

28–29 **Vienna**
1st European Catalyst Technology Conference
Details: EPC, Technology Conference
Tel: +44 (0)1483 771061
Fax: +44 (0)1483 756932
e: Europetro@cs.com

28–29 **Oslo**
23rd Offshore Pipeline Technology
Details: IBC Global Conferences Ltd
Tel: +44 (0)20 7453 5491
Fax: +44 (0)20 7636 6858
e: cust.serv@ibcuk.co.uk

29 Feb–1 March **Birmingham, UK**
Multi-Utility Infrastructure: 20/20 Vision for 2020?
Details: Pipeline Industries Guild, UK
Tel: +44 (0)20 72357938
Fax: +44 (0)20 7235 0074
e: glenister@pipeguild.co.uk

MARCH 2000

6–7 **London**
SMi's 4th Annual Conference on Reserve Acquisitions, Disposals and Swaps
Details: SMi Ltd, UK
Tel: +44 (0)20 7252 2222
e: customer_services @smiconferences.co.uk

MOVES People

Shipping lawyer **James Abbot** has moved from Stephenson Harwood's London office to Piraeus, where he will undertake claims work. The move is a result of the company's plans to expand its presence in Greece.

Enterprise Oil has appointed **Ian Craig** as Executive Director with effect from 1 January 2000. Craig is currently General Manager of the company's operations in the UK and Ireland and will become responsible for the group's production and development operations worldwide. He will also retain responsibility for the group's operations in Ireland.

Venture Production, operator of the Brighton Marine field offshore Trinidad has made four senior appointments to its management team. **Mike Wagstaff**, formerly a Managing Director with Schroders in New York, has been appointed Finance Director. **Jon Murphy**, previously a Senior Manager at Lasmo plc, has been appointed Executive Director responsible for day-to-day operations and business planning. On the operational and business development side, **Andy Bostock**, formerly with Talisman Energy, takes up the role of General Manager for the North Sea. **Jim Lee-Young**, formerly with British-Borneo, fulfils a similar role in Trinidad.

Edward J Driesse has been appointed Chief Information Officer for the Foster Wheeler Corporation, with responsibility for the company's information management technology development. He will report to the company's Chairman **Richard J Swift** and will be based at the company's headquarters at Clinton, New Jersey.

Dr Robin Landells has recently joined powertrain and vehicle engineering provider, Ricardo as the new Business Development Manager for Fuels and Lubricants.

ABS has announced two key corporate management changes. **Augustin Bourneuf Jr** has been elected Corporate Vice President, in addition to his current role as Chief Surveyor. **Thomas Miller** has been elected Vice President, General Counsel and Secretary of ABS, replacing **Joseph E Vorbach** who retired at the end of 1999.

Flow metering and equipment company SGC Ltd has appointed **Wilson Burt** as Customer Services Manager. Burt was previously with Daniel Industries in Falkirk and has 25 years' experience in the oil and gas industry.

Ombo Clinton Harry has been appointed Group Executive Director (Finance and Accounts) of the Nigerian National Petroleum Corporation (NNPC). Previously, he held management positions including Group General Manager (Accounts) at the head office and General Manager, Finance, of Nigeria LNG Ltd.

Alasdair Buchanan has been appointed Region Manager of BJ Services' Well Services Division for the Europe–Africa region. Buchanan will oversee all aspects of operations, marketing and financial management of the division in the region.

BP Amoco plc has announced the appointment of **W Douglas Ford** as an Executive Director of the company. Ford is Chief Executive of BP Amoco's Refining and Marketing division.

Ian Waldram has been confirmed as the new President of the Institution of Occupational Safety and Health (IOSH). Waldram has been an active member of IOSH for many years and is a past Chairman of the Institution's Offshore Specialist Group.

Ian Kinnear, Lieutenant Colonel, ret'd, Royal Engineers, has joined fuel system company, Alan Cobham as Business Manager – Military Fuel Handling Systems. Kinnear will also lead the Fuel Handling Systems Consortium (FHS) serving the needs of the world's armed forces, disaster relief agencies and international companies.

Pipeline Induction Heat Ltd has promoted **Phil Bond** to Managing Director. Bond joined the company in 1988 as Contracts Manager, advancing to the position of Operations Director in 1994.

Conoco has announced a number of senior management changes. **Gary Edwards**, formerly Executive Vice President, Refining, Marketing and Transportation, is named Senior Executive Vice President, Corporate Strategy and Development. Edwards becomes the principal adviser to Chairman and Chief Executive Officer **Archie Dunham. Jim Nokes**, formerly President, Refining and Marketing in North America, is promoted to Executive Vice President, Refining, Marketing, Supply and Transportation and will become a member of the Conoco Management Committee. **Richard Severance**, formerly General Manager, Mid Continent Business Unit, is promoted to President, Refining and Marketing, North America.

Ann Robinson has been appointed Chairman of the London Electricity Consumers' Committee. Robinson – who is Chairman of the Gas Consumers' Council and Chairman Designate of the proposed Gas and Electricity Consumers' Council – took up her appointment with effect from 1 January 2000.

Virginia Graham has joined Ofgem as Director of Consumer and Environmental Affairs. Formerly Director of Eurolink Age, a European organisation representing the interests of 150 national organisations campaigning on behalf of older people, Graham has also worked for many years in consumer organisations in the UK and Brussels, and has acted as a consultant in consumer and environmental affairs.