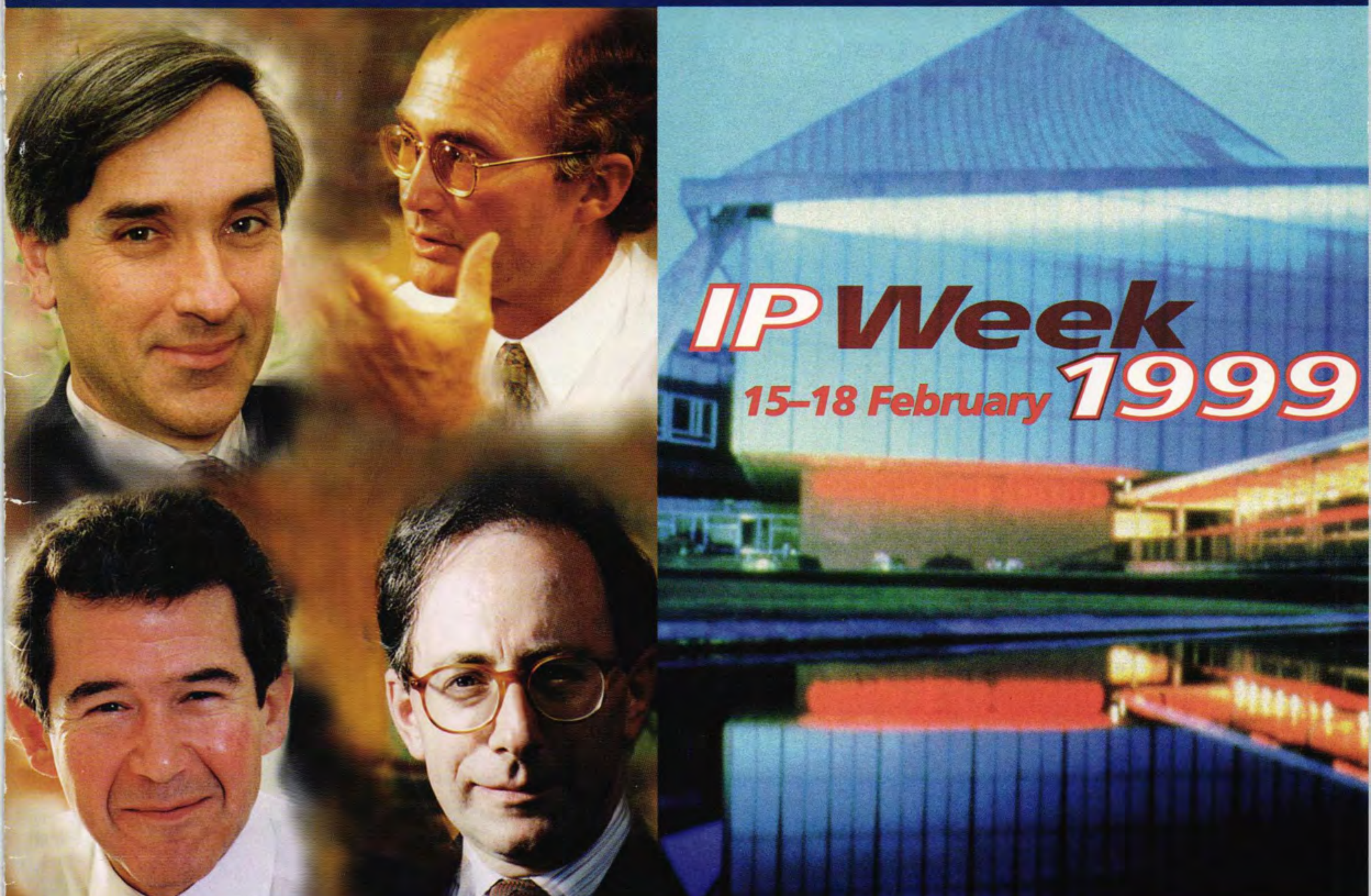
Petroleum review

FEBRUARY 1999



Caspian oil and gas
Flows begin but doubts remain

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Sulfur levels still falling

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

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover: The Commonwealth Institute, venue of IP Week 1999, and this year's speakers (clockwise, from top left): The Rt Hon John Redwood, Shadow Secretary of State for Trade and Industry; Sir John Browne, Group Chief Executive, BP Amoco; Sir Malcolm Rifkind, Director of International Strategy, BHP Petroleum Ltd; Steve Remp, Chairman and Chief Executive, Ramco Energy plc.

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ROUNDUP From the Editor

Still revising downwards

As if there was not enough gloom in the industry already, the International Energy Agency (IEA) has made a whole series of downward revisions to its oil demand projections in its latest report (published in December 1998).

For 1999 as a whole the IEA now expects oil demand to average 75mn b/d, or 0.6mn b/d, less than it was projecting only a month earlier. However if these levels are achieved they will represent growth of 1.1mn b/d, or 1.5%, notably greater than the 0.4mn b/d, or 0.5%, recorded in 1998.

Of the now projected demand growth the OECD countries account for 670,000 b/d, or 60%, of the total. Clearly the IEA is very pessimistic about an Asian recovery in 1999. China's oil demand is expected to grow by 120,000 b/d, or 2.8%, which means that the IEA believes all the rest of the world apart from the OECD and China will grow by just 310,000 b/d in 1999.

For there to be any sustained price advance in 1999, production will have to fall below demand so that the current very high stock levels are reduced to more manageable levels.

For non-Opec production the IEA now anticipates growth of just 0.4mn b/d, well down on its earlier projections. Expectations for US oil production in 1999 have been reduced by 194,000 b/d and the North Sea by 98,000 b/d compared with month earlier estimates.

Its latest view is that Gulf of Mexico production will increase by 154,000 b/d rather than 269,000 b/d while US onshore production will decline by an additional 40,000 b/d. In the North Sea output is now expected to expand by 274,000 b/d rather than the month earlier projection of 372,000 b/d. However, the UK sector of the North Sea will record the largest gain of all the non-Opec producers.

The IEA's most surprising projection is that Russian production will fall by 211,000 b/d in 1999. Russian production fell dramatically from 1990 to 1994/95, but since that date levels have stabilised, increasing slightly over the last two years.

Opec to the rescue?

There is an easy assumption that things have got so bad that Opec will have to cut production even further. In 1997 the Opec basket of crudes averaged \$18.78/b. In 1998 the average was just \$12.28/b. Surprisingly, Opec output in 1998, at 27.9mn b/d, was 2.6% up on 1997 levels according to the usually well-informed *Middle East Economic Survey* (*MEES*). Taking this level of production and the \$6.40/b cut in receipts between 1998 and 1997 suggests that Opec is currently \$178mn/d (\$65.2bn/y) poorer than it might reasonably have expected to be.

However, despite this massive loss of revenue its actions suggest the financial pain is bearable and the omens for further Opec cutbacks are not good. Compliance with the agreed reductions is already steadily eroding – from over 90% in October 1998 to 73% in November and 67% in December.

The annual production totals calculated by *MEES* suggest real tensions in the organisation. In 1998 the winners were Iraq (+930,000 b/d), Saudi Arabia (+120,000 b/d), Qatar (+43,000 b/d) and the UAE (+16,000 b/d). In contrast the other Opec members recorded production declines with Venezuela (–97,000 b/d) and Nigeria (–115,000 b/d) notably lower.

Over time low oil prices will cure themselves as demand is stimulated and new supply reduced. However the key question is: in the short term will companies and countries resist the temptation to boost cashflow by expanding production? Similarly will consumer governments re-establish a direct link between low oil prices and expanding demand by reducing taxation on oil products? Two noes and 1999 looks rather bleak.

Mea Culpa

In last month's editorial I suggested that Nelson might have enjoyed the benefits of the British Navy's policy of active retirement on half pay after the Napoleonic Wars. As Nelson died at Trafalgar in 1805 and Napoleon was not defeated until 1815, this was just plain wrong. My thanks to the reader who drew it to my attention. My apologies to all readers.

This month we are pleased to include a highly topical article by Trevor Ridley of BHP Petroleum in which he explains a computer-based project evaluation method particularly suitable for marginal prospects. A notable feature is the visualisation of the risk profile. In 1999 offshore projects in expensive areas such as the North Sea, the Gulf of Mexico and offshore West Africa will require very robust risk profiles if they are to go ahead. We believe this is the first time probabilities of a financial outcome have been displayed in this way in an industry publication.

Chris Skrebowski

Web World

The Year 2000 has huge implications for IT systems everywhere, but the turn of the millennium is also significant to the oil and gas industry.

From 1 January 2000, the sale of leaded petrol will be banned in the UK. The newly launched UKPIA site (**www.ukpia.com**) is full of useful information on the leaded/unleaded petrol issue. Here you'll be able to find out whether your car will still be running next year, and learn enough to impress your friends and family. There's also an information leaflet and a technical leaflet, depending on how keen you are.

Elsewhere on the site there are views on climate change, the EU acidification strategy, benzene in petrol, and fine particulates. The full text of *UKPIA News* is also available. There is plenty of legislative material, including the EU Fuels Directive and a white paper on the Future of Transport.

For even more details you can visit the European Union website (**www.europa.eu.int**). The section on the new euro currency bears the legend 'interesting information is to be found here' – just don't get carried away and try paying your *Petroleum Review* subscription fee in euros!

EUROPIA (**www.europia.com**), the European government affairs organisation of the oil refining and marketing industry in the EU and EEC, offers details of its own activities, along with links to other relevant sites.

The Concawe site (**www.concawe.be**) holds technical and economic studies relevant to oil refining, distribution and marketing in Europe. Many of its publications are available online, along with some free downloads.

You can access links to all of these sites plus much more on the IP website (**www.petroleum.co.uk**).

The IP is planning to expand the amount of searchable data it holds on the site. At the moment it is building a database of *News in Brief* stories to improve the value of this service.

A Member only section is also to be introduced, so make sure your membership is up-to-date! You can already search the Library Catalogue, the Publications Catalogue and *International Petroleum Abstracts*, and more pages are constantly being added to the site.

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

HSE stats show rise in UK offshore accidents

The UK Health & Safety Executive's (HSE) latest offshore accident and incident statistics show a rise in the number of offshore accidents in the 12-month period from April 1997 to March 1998 compared with the previous year.

The report reveals that:

- there were three fatalities arising from two incidents, compared with two fatalities in the previous year;
- the number of major injuries rose from 45 in 1996/97 to 59, with an increase in the major injury rate from 167.6 to 256.5 per 100,000 employees;
- the number of over three-day injuries decreased from 304 to 292, while the rate for the same type of injuries showed an increase from 1,132.1 to 1,269.6 per 100,000 employees;
- certain offshore operations are associated with a higher incidence of injuries, in particular drilling/workover, deck and maintenance operations;
- finger and back injuries dominate, with the most common types of accident involving slips, trips and falls, and handling goods and materials.

The statistics also provide a valuable pointer as to where the industry, through its Step Change initiative launched in September 1997, should focus future effort in its continuing quest to improve safety performance in offshore North Sea operations by 50%. Step Change was established as a cross-industry initiative embracing all sectors of the industry, including contractors, service companies, operators and owners of installations and the workforce, with input from trade unions, regulators and academics. Measures already introduced through Step Change include:

- personal safety performance contracts signed by senior management;
- the creation of an offshore installation managers network which provides a formal framework for installation management to share ideas and good practice in the area of safety management;
- steps to introduce a more uniform approach to aspects of safety management, such as identifying common safety performance measurements and establishing an industry-wide approach to induction training for new personnel joining offshore installations;
- the drilling contractors, in conjunction with the operators, have set up workgroups to deal with safety critical issues identified in the drilling operation;
- a project to improve the communication of the safety message with the dissemination of the 'Communicating the Safety Case' document throughout the industry;
- the development of an offshore passport system, providing a comprehensive record of an employee's training, experience and time offshore;
- a series of workshops to build direct workforce involvement into the Step Change programme.

Iranian Caspian study programme agreed

Lasmo, Shell and the National Iranian Oil Company (NIOC) are to conduct an exclusive exploration study in the southern Caspian Sea. It is understood that BP may join the 18-month project at a later date.

The consortium is to acquire 10,000 km of 2D seismic and conduct geological and geophysical studies over a large and previously unexplored area.

The partners will also have preferential rights to select up to four blocks and negotiate service agreements over a 12-month period after the study has been completed. Within the first six months, the consortium will also identify prospects where seismic data already exists and select two additional prospective areas.

Commenting on the project, Chris Wright, Lasmo's New Business Director, said: 'The study programme represents a major strategic entry into the Iranian Caspian for Lasmo. We will be looking at this agreement as a base on which to build further interests in the Iranian upstream sector.'

North Sea Brown field produces first gas

The small Brown gas field in southern North Sea block 49/30 has come onstream. Initial production is forecast to reach 38mn cf/d of gas. Output is commingled with that of the nearby Davy field and transported via an existing pipeline to Indefatigable, from where it is carried to the Amoco terminal at Bacton, Norfolk. Brown is expected to have a four-year field life. Amoco (operator) holds a 22.22% stake in the project, with British Gas holding a 50% interest and Amerada Hess the remaining 27.78%.

According to the UK Department of Trade and Industry there are now 200 offshore producing fields on the UK Continental Shelf – 105 are oil producing, the remaining 95 are gas/condensate fields. Over £177bn has been invested in bringing these fields onstream to date.

In Brief

United Kingdom

BP is reported to be considering the *temporary closure of the 30,000 b/d Ula oil field in the Norwegian sector of the North Sea due to low oil prices. BP holds a 57.5% stake in the field.*

Shell UK has acquired BP's entire *18.75% interest in West of Shetland licence P799 bringing its total stake to 37.50%. Shell has also acquired an additional 5% stake in BP's West of Shetland 16th round licences P917/918/919 – it now holds a 55% interest in the area.*

BP Exploration is understood to be *buying Saga Petroleum's 12% interest in the Miller oil field in the North Sea for $45mn.*

Monument Oil and Gas is to sell its *20.32% interest in the North Sea Johnston field to Eastern Group for £19.7mn. The deal also includes Monument's stakes in blocks 43/27a and 43/26a, excluding acreage containing the Ravenspurn North field.*

Conoco is understood to have boosted *its southern North Sea asset portfolio with the acquisition of Canadian Petroleum's interests in the producing Caister (30%), Vulcan (7.88%) and South Valiant (12.5%) fields. The deal also includes the purchase of some long-term gas supply contracts and Canadian Petroleum's stake in four discoveries and three exploration blocks.*

Arco British has taken a 20% stake in *UK offshore licence P787 and a 50% interest in P063, in North Sea blocks 53/5b and 54/1a respectively, from Enterprise Oil as part of a farm-in agreement. Arco has also assumed operatorship of block 54/1a. Revised interests in P787 are: Arco British 40%, Fina Petroleum Development 40% and Enterprise Oil Exploration 20%. Interests in P063 are: Arco British 50%, OMV (UK) 25% and Intrepid Energy North Sea 25%.*

Europe

Statoil is reported to have cut its 1999 *exploration budget for the Norwegian North Sea by 20% compared with last year. Continued low oil prices and the drilling of a number of expensive dry wells in 1998 are understood to have contributed to the budget cut.*

NEWS Upstream

Britannia inauguration

Peter Mandelson, the former UK Secretary of State for Industry, officially inaugurated the Britannia gas condensate field at Kvaerner's Port Clarence fabrication yard on Teesside on 11 December 1998. The day before, the field – following the recent completion of the B3 well – achieved a record output of 605mn c/d of gas and 45,000 b/d of condensate. Peak output is currently slated at 740mn cf/d of gas and 50,000 b/d of condensate.

The field is jointly operated by Chevron and Conoco via Britannia Operator Limited. Recoverable reserves of 3tn cf will give the field a 30-year lifespan and enable it to meet 8% of UK gas requirements.

Brazilian licensing round

Brazil has announced its first oil and gas licensing round following the passing of new petroleum legislation in August 1997. The legislation has facilitated sweeping changes within the Brazilian energy sector through a comprehensive programme of market-oriented reforms – including the removal of subsidies, import controls and price controls on crude oil, refined products and natural gas – and marks the end of the 45-year operating monopoly of Petrobras. It has also provided the legal framework to open up Brazil's oil and gas sector to private involvement.

The licensing round has a threefold objective:

- to broaden and accelerate the exploration effort within Brazil;
- to facilitate the transfer of appropriate technology and 'best practice' to the sector; and
- to encourage the development of a robust and dynamic private sector, open to both foreign and domestic companies.

The areas under offer are very large by most standards – averaging 5,000 sq km (about the same as 250 Gulf of Mexico blocks) – with exploration periods lasting up to nine years. Of 27 blocks being offered, 23 are in seven offshore basins including 12 in the Campos and Santos Basins. The round covers both deep water acreage in frontier and proven basins as well as shallow water plays. A number of onshore gas plays in the largely unexplored Parana Basin and low-risk exploration in the onshore Potiguar Basin are also under offer. Brazil currently produces more than 1mn b/d of oil. Plans are to increase this to 2mn b/d by 2005.

Kvaerner secures southern North Sea deal

Kvaerner Oilfield Products is to supply a two-well subsea control system for the BG Exploration and Production Easington Catchment Area (ECA) development in the central North Sea. The company secured the contract from Mentor Project Engineering on behalf of ETPM (UK).

Phase 1 of the ECA project involves the development of the Mercury and Neptune fields, tied back to the BP Cleeton platform via a normally unattended wellhead platform (WHP) at the Neptune field. The subsea development comprises two subsea satellite production wells producing in 35 metres of water to a single manifold at the Mercury location, tied back to the WHP via a 26-km umbilical and flowline.

The control system to be supplied by Kvaerner is designed for a 10-year life of field. It will be delivered in July 1999.

Natuna gas to be remarketed following cost cuts

The Indonesian government is reported to be planning to restart marketing gas from the East Natuna field following Mobil's development of an integrated LNG floating barge technology which is said to be capable of providing LNG at a much lower cost than has previously been possible.

Mobil holds the exploitation rights to the field which is estimated to hold 42tn cf of natural gas with a high carbon dioxide content. The high cost of stripping the carbon dioxide from the gas using conventional methods has kept the price of Natuna gas uncompetitive until now.

In Brief

***TOTAL has sold its North Sea upstream** assets – including an 11.5% stake in the Conoco-operated Murdoch gas field and the related interest in the Caister Murdoch System of gas pipelines – to Gaz de France for an undisclosed sum.*

***Saga Petroleum's North Sea Varg field** is reported to have come onstream and is expected to reach a plateau output of 50,000 b/d in 1Q1999. The field has reserves put at 35mn barrels of oil.*

***Statoil has submitted a plan for development** and operation of the Sygna North Sea field to the Norwegian Ministry of Petroleum and Energy. It is proposed to develop the field via a subsea template with two production wells tied back by a flowline to Statfjord C. The field holds an estimated 63mn barrels of recoverable oil reserves.*

North America

***Statoil reports that it has sold a 50%** stake in the Viking gas field in the Gulf of Mexico to US company ATP for an undisclosed sum.*

***BP Exploration is reported to have** delayed the start-up of the Northstar offshore oil project in Alaska by a year until late 2001 in light of the continued weak oil price. Recoverable field reserves are estimated at 130mn barrels of oil.*

***Shell's Cinnamon field in Green** Canyon block 89 in the Gulf of Mexico is reported to have come onstream, producing 1,930 b/d and 1.4mn cf/d of natural gas. Peak output is expected to exceed 3,000 b/d and 2mn cf/d of gas.*

***Development of Texaco and** Marathon's Petronius field in the Gulf of Mexico is reported to have been delayed until at least 2000 following the sinking of part of the platform's topsides when being lifted into place. The $500mn project had been due onstream in 1999.*

Middle East

***TOTAL is understood to be negotiating** with the Iranian authorities the development of a large oil field onshore Iran, together with two additional deposits in the Sirri field.*

***Saga Petroleum is reported to be** involved in discussions with Iran regarding the development of the Dehl Uran and Cheshmeh-Khosh oil fields.*

Low oil price hits UK output again

UK daily oil revenues fell again in November 1998 to £17.4mn and are now at their lowest level in real terms since The Royal Bank of Scotland's *Oil Index* was first published in 1983, according to the latest edition of the report.

The fall in revenues is directly attributed to the price of Brent crude falling to $11.07/barrel, representing a fall of 12.1% since the previous month and 42% since November 1997.

The Royal Bank predicts that there 'is little prospect of an imminent rise in prices, with demand weak and stocks high', and says that 'the clear task now is to find ways of living profitably in the long-run with lower prices'.

In November 1998 oil output reached its highest level of the year, with an increase of 12,030 b/d over the previous month, an increase of 1.7% since November 1997.

Over the same 12-month period, gas output rose by 6.3% on the year to its highest level since January.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Nov 1997	2,568,987	10,015	19.07
Dec 1997	2,709,258	10,880	17.38
Jan 1998	2,598,757	11,012	15.20
Feb 1998	2,582,700	10,305	14.07
Mar 1998	2,595,594	9,803	13.17
Apr 1998	2,571,241	8,844	13.53
May 1998	2,433,059	6,381	14.40
Jun 1998	2,406,521	6,069	12.12
Jul 1998	2,432,040	5,733	12.06
Aug 1998	2,379,644	5,640	12.05
Sep 1998	2,573,882	6,394	13.28
Oct 1998	2,600,813	8,828	12.60
Nov 1998	2,612,843	10,642	11.07

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Revised offshore safety case guidance published

The UK Health & Safety Executive (HSE) has published revised guidance to support the Offshore Installations (Safety Case) Regulations 1992 (SCR). The primary purpose of the revised guidance is to reflect the changes to SCR introduced by successive sets of regulations which have been implemented following the public inquiry by Lord Cullen into the 1988 Piper Alpha disaster.

The publication complements the document *Assessment Principles for Offshore Safety Cases*, published in July 1998, which aims to promote a better and wider understanding of the principles against which HSE assessors evaluate the acceptability of safety cases for offshore installations.

The SCR require the submission to HSE of a safety case document for every fixed oil and gas installation operating in UK waters, and any mobile installation moving into UK waters to operate there. Safety cases must demonstrate that there is an effective health and safety management system on the installation, that all major accident hazards have been identified and that controls are in place to reduce risks to people as far as reasonably practicable.

In Brief

Kuwait is understood to be hoping to *attract $7bn of foreign investment to develop its northern fields over the next five years and double regional production to over 900,000 b/d of oil.*

TOTAL and the National Iranian Oil *Company (NIOC) are reported to be upgrading the oil processing facilities on Sirri Island in the Persian Gulf as part of the $610mn Sirri A and Sirri E projects. A new 50,000 b/d separation train is under construction, in addition to the existing 100,000 b/d facility, together with a new 160,000 b/d water injection system, 10 MW power plant and flaring system.*

Russia & Central Asia

Socar has awarded Frontera Resources *and Delta Hess a $790mn contract for the rehabilitation of the Azeri Kursanga and Karabalga onshore oil fields which are believed to hold in excess of 100mn tonnes of recoverable reserves.*

Exxon (66.7%) is understood to have *agreed the principles under which it will participate in the Sakhalin-3 project, together with Rosneft and its subsidiary Rosneft–Sakhalinmorneftegaz (sharing 33.3%). The US company is also reported to have called for the Russian government to accelerate the inclusion of the Ayashskiy and Vostochno-Odoptinsky blocks in the register of fields being developed under production sharing agreements.*

Azeri state-owned company Socar and *a consortium of four Japanese companies – Japex, Inpex, Itochu and Teikoku – are reported to have signed a $2.3bn contract to develop the Ateshgyakh, Yanan Tava and Mugan Deniz fields in the Azeri sector of the Caspian Sea. Reserves are put at between 100mn and 150mn tonnes of oil.*

A consortium of international oil com*panies is reported to have signed an agreement with state-owned Socar to develop the Kyursangi-Karabagly field onshore Azerbaijan. Field reserves are estimated at 150mn tonnes of oil.*

NEWS Upstream

Triton FPSO conversion gets underway

The newly built ship for the Triton project entered the River Tees on schedule on 6 December 1998. The vessel is currently moored at the Tees Offshore base, where 7,500 tonnes of process and utilities equipment will be installed and commissioned by Kvaerner Oil & Gas's Port Clarence fabrication facility where the process topsides are being constructed.

The vessel will be towed to the Triton development, which comprises the Bittern, Guillemot West and North West fields, in summer 1999. Field partners are Amerada Hess, Veba Oil & Gas UK, Shell UK, Esso, Paladin Resources and Enterprise Oil. *(Photo © David Evans Photography)*

Asia-Pacific

***Unocal and Mobil are understood to** have unveiled plans for the fast-track development of the deepwater West Seno oil and gas field offshore Kalimantan in Indonesia. Field reserves are put at 150mn boe. First production is expected in 2001.*

***Pertamina is reported to have** announced plans to sign 20 new contracts in 1999. It is also understood that 48 foreign operators have pledged to invest $5.3bn in E&P in the region this year, $1bn more than 1998, despite the continued low oil price and economic and political crisis in Indonesia.*

***Esso Production Malaysia is reported** to have installed a new satellite platform, Tapis E, offshore the coast of Terengganu, Peninsular Malaysia. The platform, which extends development of the western and south-western areas of the Tapis field, is expected to produce at a peak rate of 25,000 b/d.*

***Pertamina of Indonesia is reported to** have cancelled contracts for 152 projects, most of which are linked to the family and associates of the former President Suharto, due to alleged corruption in the way in which they were awarded. The contracts for seven further projects, including the Balongan refinery in West Java, are currently under investigation.*

***Chevron has entered the Thai gas** market following its acquisition of Rutherford Moran Oil Corporation for $91mn.*

***India's first bidding round under its** new exploration licensing policy is understood to comprise 12 blocks offshore the east coast. The deepwater blocks on the west coast are not being offered.*

***China Offshore Oil Bohai Corporation's** Qikou 18-1 and Qikou 17-1 wells in the western part of the Bohai Sea are reported to have produced first oil.*

In Brief

***Australian crude oil and condensate** production is expected to increase to between 590,000 b/d and 710,000 b/d according to the Australian Geological Survey Organisation. The country currently produces 570,000 b/d. However, output is forecast to fall to between 280,000 b/d and 530,000 b/d in 2010 as domestic resources diminish.*

Latin America

***PdVSA and Venezuela's Zulia state** university are reported to be planning to form a joint company – Oleoluz – to develop the Mara Este marginal oil field in western Venezuela. Proven field reserves are put at 89mn barrels.*

***PdVSA is reported to have put its** $3.5bn Ameriven venture with Arco, Phillips and Texaco on hold due to project financing uncertainties. Plans were to extract and upgrade 197,000 b/d of extra-heavy crude in the Hamaca area of the Orinoco Belt. The Venezuelan state oil company is also reported to have ended its joint venture with Coastal Corporation under which 90,000 b/d of extra-heavy crude oil in the Suata area of the Orinoco Belt was to be extracted and upgraded.*

Africa

***Elf Aquitaine is understood to have** made a new oil discovery in block NC137 offshore Libya. The B3 discovery well tested at 3,600 b/d of crude oil. Reserves are put at between 100mn and 150mn barrels with first production expected by early 2001.*

***Texaco and Famfa Oil of Nigeria** report that their Agbami-1 wildcat discovery on OPL block 216 in the central Niger Delta indicates 'significant' reservoirs of 35° to 45° API oil with very low sulfur content. Reserves are preliminarily estimated at several hundred million barrels of recoverable oil.*

***A consortium comprising Repsol** (operator, 40%), TOTAL (30%) and OMV (30%) report that the M-1 discovery well in block NC-115 in the Murzuq Basin in southern Libya has flowed 2,500 barrels of high quality light crude in production tests. The companies expect output to rise to 8,000 b/d by 'using standard pumping techniques'. Potential reserves are put at between 100mn and 200mn barrels.*

Shell restructures Group portfolio

Shell Chairman Mark Moody-Stuart has unveiled a five-year plan aimed at significantly increasing Group earnings while lowering costs. Speaking in London on 14 December 1998 he announced that 40% of the company's Chemical portfolio will be sold. Areas of 'high cost oil production and refineries are also being addressed', he said. In order to achieve targets set, special charges (including write downs) of up to $4.5bn after tax are expected in 4Q1998.

The company is also looking to achieve total cost improvements of $2.5bn/y by 2001. In addition, there will be a much greater degree of executive accountability at all levels in Shell, with executive structures replacing the business committee system.

Moody-Stuart stated that the Group could expect 'little help from the business environment' with the price of Brent crude over the next five years forecast to average $14 with global economic growth predicted to be, at most, 2%. Despite this, he pledged that Shell aims to deliver returns on average capital employed of 14% and increase oil and gas volumes by 10% and 25%, respectively, by 2001. Moody-Stuart also forecast that oil prices could well remain at around $10/b for the next year or so, but stated the company would be able to maintain its financial strength and flexibility in such a low price regime. Capital investment of $11bn/y is planned and the dividend policy remains unchanged.

The Group has already announced job losses totalling 4,000 out of 105,000 employees. Some estimate that these latest measures may result in up to 7,000 further job losses.

In terms of mergers, Moody-Stuart stated that the company had the 'capacity to take up real growth opportunities – such as the opening of low cost production areas or distress sales'. The Group planned to continue to look at merger possibilities and act 'if the right opportunity arises'. However, he pointed out that the Group was 'large enough to be the leading company on our own without any merger'.

EU assists Azerbaijan

A package of initiatives is being developed by the European Union to integrate Azerbaijan into the world economy as a future key oil producer and regional economic power.

The European Commission has granted the Azeris euro 11mn in aid, on top of the euro 29mn that it has already provided in the last 12 months. The EU has also been providing assistance through the Tacis programme for linking European oil and gas networks with those in the region via the Black Sea.

A recent meeting between the EU and Azerbaijan has also been assessing means of improving the business climate in the former Soviet republic.

New Year Honours

A number of oil and gas industry personnel have been awarded New Year Honours, including the award of a CBE to Clare Spottiswoode, former Director General of Gas Supply for her service to the gas industry and consumers.

Eric Findlater Brandie, Manager, Health, Safety and Environmental Affairs at Tengizchevroil was also awarded an OBE as were Prof Peter Dunn for service to the development of Innovative Energy Technologies and Ian Dussek, Director, Wells, for service to highways and the bitumen industry. Roger Cartwright, Senior Policy Advisor Latin America, British Petroleum, and Walter McGillivray, Production Training Branch Leader, BP Oil, were awarded MBEs.

UK government fast-tracks clean air plan

The UK government plans to speed up action to reduce key air pollutants following publication of the results of a wide-ranging review of the UK National Air Quality Strategy.

The date for achieving agreed concentrations of benzene (5 ppb measured as a running annual mean), 1,3-butadiene (1 ppb; running annual mean) and carbon monoxide (10 ppm; running 8-hour mean) has been brought forward from 2005 to 2003, with a new, tougher indicative level to be set for benzene (1 ppb by 2005), while that for lead (0.5 μg/m³; annual mean) has been brought forward from 2005 to 2004 with a new, tougher objective (0.25 μg/m³) set for 2008.

For nitrogen dioxide, the annual objective (21 ppb; annual mean) is not to be changed, but the hourly objective will be tightened to 104.6 ppb (previously 150 ppb). Objectives remain unchanged for ozone (50 ppb; 97th percentile of running 8-hour mean) and sulfur dioxide (100 ppb; 99th percentile of 15-minute mean), while the present objective for particles (50 μ/m³; 99th percentile of 24-hour mean) is to be retained as an indicative level.

In Brief

United Kingdom

The Scottish National Party (SNP) may *have overestimated the share of North Sea oil revenue that would be held by an independent Scotland, according to a recent study conducted by Professor Alex Kemp of Aberdeen University on behalf of* The Economist. *The report indicates that Scotland, if declared independent, would receive only 66% of UK North Sea oil and gas revenues (a figure that could fall to 45%) rather than the 90% of revenues cited by SNP.*

BP Amoco is reported to be cutting *900 jobs in its upstream E&P division in the first phase of a major rationalisation of its 100,000-strong global workforce. Approximately 500 of the job losses are expected to be from the former Amoco headquarters in London.*

UK independents Enterprise Oil and *Lasmo are reported to be in talks on a £2.3bn merger.*

UK independent British-Borneo Oil & *Gas reports that it expects to achieve £8mn in annual cost savings following the acquisition of Hardy Oil & Gas last year. Cost savings were originally forecast at between £2mn and £3mn.*

UK independent oil company *Enterprise Oil is understood to be planning to cut its 1999 exploration budget by 40% to £100mn. The company's UK operations are also being relocated to Aberdeen, leaving a small core workforce in London. A number of job losses are expected.*

BG plc is understood to be planning to *demerge its Transco gas pipeline business from its oil and gas exploration and production operations.*

Milford Haven port authority has been *fined a record £4mn for the pollution caused as a result of the grounding of the* Sea Empress *in February 1996.*

Arco is understood to be planning to *cut 100 jobs from its UK operations as part of the company's $500mn cost cutting programme.*

Europe

The privatised Spanish power group *Endesa is reported to have acquired 3.6% of Repsol's shares for $573mn. The deal follows Endesa's recently completed strategic alliance with Gas Natural, the gas group controlled by Repsol.*

Chevron to fund upstream growth and cut costs

Chevron has announced a \$5.1bn capital and exploratory spending programme for 1999 – 8% less than projected spending for 1998. Much attention will focus on long-term growth projects in Kazakhstan, West Africa and the Gulf of Mexico. Nearly \$3.7bn of the total investment programme will be spent in worldwide exploration and production. About \$2.6bn of this will be invested in US operations. The company plans to invest \$870mn, of which more than \$540mn will be spent in the US, including continuous upgrading of the company's service station network. Most of the remainder will be invested outside the US by Chevron's 50%-owned affiliate, Caltex. Chevron plans to invest \$380mn in the worldwide chemicals business in 1999.

The company has also revealed plans to reduce expenses by \$500mn in 1999. Cuts are expected to be accomplished primarily in Chevron's mature North American exploration and production business, as well as in refining and marketing, and chemicals. Chevron has already cut more than \$2bn from its annual operating expenses since 1991. Some job losses are anticipated out of the 34,000-strong global workforce.

Commenting on the current merger trend in the oil industry, Chairman Ken Derr said: 'We will consider mergers or acquisitions as one possible way to improve business results. But it is not necessary for Chevron to merge with a competitor to continue to provide top returns to our shareholders.'

Merger creates new additives venture

Infineum – the new petroleum additives enterprise arising from the worldwide joint venture between Exxon Chemical, Shell Petroleum and Shell Chemical – became fully operational last month.

According to Tony Gaskell, President and Chief Executive Officer, the new company will provide fuels and lubricants customers with a 'more flexible product range supported by worldwide research and development facilities'.

Recent industry consolidations, declining additives margins, complementary component and formulation technologies and decreasing product lifecycles are understood to be the four key drivers behind the joint venture rationale.

Infineum first unveiled its new corporate identity at the end of 1998 following the 30 September divestiture of Exxon's Viscosity Index Improver business which cleared the path for the two additives businesses – Paramins and Shell Additives – to begin start-up preparations.

BP Amoco backs energy tax on business

Speaking to the Fabian Society, BP Amoco President and Deputy CEO Rodney Chase has acknowledged that there is a limit to what companies will do voluntarily to curb their energy emissions, and that an energy tax could be a 'powerful instrument for changing behaviour'. However, he also argued that, in many instances, 'there are other economic instruments which offer greater benefits than taxation', and that 'an energy tax could do more harm than good if we are not very careful with its design'.

BP Amoco's preference is for an emissions trading system which, the company believes, provides the 'most economic and most effective route' for reducing emissions. But Chase also said that a tax which 'rewards certain behaviours' could also have a role to play in meeting Kyoto targets at minimum cost. He suggested that consideration be given to introducing a reduced rate of corporate taxes for companies which succeed in reducing their emissions over an agreed baseline. Another possibility was to agree targets for emission reductions, and tax only the quantum by which the target is exceeded. Both proposals are seen to be better than the conventional energy tax on businesses which taxes energy use rather than carbon emissions and does not address other greenhouse gases.

Chase also warned against efforts to achieve revenue neutrality by reducing employer's National Insurance contributions as compensation for an industrial energy tax as 'such an approach would introduce a fiscal bias against investment and capital intensive industries' and would 'impose the highest penalties on some of the UK's best performing companies'.

In Brief

***TOTAL is reported to have forecast at** least 1,000 job losses following its merger with Petrofina. The losses will be from both companies.*

North America

***Houston-based Conoco has unveiled** plans to cut costs and reduce capital spending in response to low oil prices. The company is understood to be planning to take a \$50mn charge in the 4Q1998, cut 1999 capital expenditure by 21% and axe around 1,000 jobs.*

***US oil services group Halliburton is** understood to have announced the loss of over 2,500 jobs due to the continued low oil price. The job losses are in addition to the 8,100 redundancies announced after the acquisition of Dresser Industries in September 1998.*

***Arco reports that its 1999 capital** spending will be \$2.7bn, down 25% from 1998 spending. Included in the budget will be new production projects such as the Alpine field on the North Slope of Alaska, Shearwater in the North Sea, and properties obtained in the third Venezuelan licensing round. The company hopes to achieve \$350mn of cost savings in 1999 as part of its cost cutting programme announced in October 1998 which aims to reduce costs by \$500mn over two years.*

***Gulf Canada Resources is reported to be** planning to cut its workforce by 10%.*

Russia & Central Asia

***Romanian state oil company Petrom is** understood to be restructuring its business. Plans include a 30% cut in workforce, the closure of over 1,000 inefficient wells and the shutting down of a number of sections of its three oil refineries in a bid to improve operational efficiency and make the company more attractive for privatisation.*

***Announcing its preliminary results for** 1998, Lukoil reported a 33% increase in exports and a 12.7% reduction in operating costs, according to United Financial Group's* Russia Morning Comment. *Oil production is reported to have risen by 3% to 1.29mn b/d, a level that is expected to be maintained in 1999. Gas production rose by 13%. Refining utilisation rose from 70% in 1997 to 76.2% in 1998, some 13% above the average for Russian refineries.*

***Ruhrgas is reported to have secured** 2.5% of Gazprom for \$660mn.*

NEWS Downstream

Fruehauf secures record-breaking tanker contract

Fruehauf has won what it claims is its largest single order to date for its millennium petroleum spirit tank trailer (see *Petroleum Review's Retail Marketing Supplement*, March 1998). The UK road tanker and trailer manufacturer is to supply BP with 56 tankers under the terms of the £3.75mn order.

Redesigned from first principles, the new tanker is said to meet pending legislation under the European ADR Framework Directive governing the carriage of dangerous goods by road in EU member states, due to be implemented on 1 January 1999. The tanker is also claimed to offer improved safety and reliability compared with previous models and an additional 450 kg of payload. The tank barrel comes with a 10-year warranty.

European hauliers to adapt operations

European road tanker operators will have to adapt their operations to the amendments required under the European ADR Framework Directive governing the carriage of dangerous goods by road in EU member states which is due to be implemented on 1 January 1999.

The International Road Transport Union (IRU) reports that with its Group of Experts on the Transport of Dangerous Goods is has worked hand-in-hand with representatives of 35 signatory countries to the ADR to adapt the regulations to the needs of the market, the safety of people and the environment.

Regulatory changes include the following.

- The list of onboard safety equipment to protect the driver, the public and the environment when an accident or incident occurs, has been reduced. The list used to include items which were often unnecessary for the transport in question, explains IRU, and which consequently were not carried in the vehicle. This resulted in many infringements at roadside checks, despite the safe nature of the transport. As of 1 January 1999, the shipper will add to its 'Instructions in writing for the driver' the safety equipment that is useful for the goods loaded.
- The list of certain groups of dangerous goods that do not fall under the provisions of ADR when transported in small quantities has been shortened.
- Employers will be required to train and instruct employees involved in loading and unloading, packaging etc, of dangerous goods. In principle, this confirms what many employers already do on their own initiative or on the basis of national legislation. With this provision, safety and competition conditions are harmonised, comments IRU.
- The untimely scrapping of a certain category of well-built tankers has been avoided, IRU also states. Under the previous provisions, tankers built between 1985 and 1989 would have been phased out, the latest in 2005. Such vehicles can now remain in service until 2011.

In Brief

United Kingdom

***UK gas industry watchdog Ofgas** has appointed WS Atkins Consultants to make an independent assessment of gas companies' Year 2000 compliance plans.*

***Fina claims to be the first UK petrol** retailer to install technology to accept the new Switch Solo and Electron online debit cards at its service stations.*

***The Future and Options Association** (FOA) has published guidelines aimed at helping the London exchange-traded futures and options market deal with the Millennium Bug.*

***PowerGen is to pay £534mn to BHP** Petroleum (operator), Lasmo, and Monument Oil and Gas in order to reduce the price it pays for Liverpool Bay gas by 35%. The gas is used by PowerGen's 1,450 MW Connah's Quay power station in north Wales.*

***Gas prices in the UK are reported to be** the second lowest out of 13 industrialised countries, according to a recent survey by National Utility Services (NUS). UK prices fell by 2.7% in the year ending September 1998.*

Europe

***Statoil and Norwegian–Swedish** ICA/Hakon supermarket group have formed a partnership covering 1,500 Scandinavian service stations. The new 50:50 venture will offer groceries, fast food, motor fuels and car services.*

***Germany is reported to have opened** what is claimed to be Europe's first liquid hydrogen service station in Hamburg. The site is seen as a 'symbolic' gesture as, at present, the use of direct hydrogen injection to fuel cars is impractical and uncommercial.*

***BP and Mobil Oil are understood to be** planning to invest FFr280mn in 1999 in a bid to improve performance at their Lavera and Notre-Dame de Gravenchon refineries in France. Plans include increasing production at Lavera by 60% to 350,000 t/y at a cost of FFr100mn.*

North America

***Unocal is reported to be receiving** $50mn for the sale of its 9.1% stake in the Alliance natural gas pipeline to Westcoast Energy.*

Europe tackles lorry and bus pollution

Europe's air is set to become cleaner following an agreement by Environment Ministers at the Council in Brussels to cut pollution from lorries and buses by 60%. According to UK Environment Minister Michael Meacher, such vehicles 'are responsible for 55% of particulate and 39% of oxides of nitrogen emissions'. The new agreement requires new heavy duty vehicles to cut their emissions of:

- particulates by 30% by 2000, and by a further 80% by 2005, through the use of particulate traps;
- oxides of nitrogen by 30% by 2000, and on confirmation of the technical feasibility of state of the art technology to be reviewed in 2002, a further 60% by 2008; and
- hydrocarbons and carbon monoxide by 30% by 2000, and a further 30% by 2005.

Also agreed was:

- compulsory labelling of all new cars sold, giving consumers clear information on fuel consumption and carbon dioxide (CO_2) emissions; and
- the collection of data to monitor the voluntary agreement reached with European car manufacturers (ACEA) in October 1998 to reduce CO_2 emissions from new cars by 25% by 2008.

Ofgas extends competition in UK gas storage

Ofgas has announced new arrangements for the auctioning and trading of gas storage, starting in 1999. It is hoped that the new arrangements will provide a better balance of gas supply and demand, and in particular should reduce prices of peak winter gas which, in turn, benefit domestic gas customers.

The new arrangements provide for auctions of capacity in British Gas's Rough and Hornsea gas storage facilities and replace the present system where prices are regulated by Ofgas. The storage facilities will be managed by British Gas Storage. A secondary market will also be established, where owners of storage capacity rights will be able to sell them to third parties.

There will be four auctions carried out during the 1999 storage year:

- 50% Hornes capacity, for a 5-year term;
- 50% Rough capacity, for a 5-year term;
- 50% Hornsea capacity. for a 1-year term; and
- 50% Rough capacity, for a 1-year term.

First-ever gas to electricity pricing contract

UK integrated money and securities broker and financial provider Garban claims to have brokered the first-ever gas indexed to electricity pricing contract. The five-year contract will provide an unnamed power station owner with lower priced gas to power plant turbines while reducing the energy supply company's exposure to the daily volatility of gas prices in the spot market, states Shezad Abedi, Managing Director of Garban Energy.

The brokered transaction is non-tradable. However, this will not prevent the power station owner from selling unused gas that has to be bought under the terms of the contract back into the wholesale gas market. Neither does it prevent the energy company risk manager from hedging forward separately on the gas price that has been agreed between two parties.

According to Abedi: 'The freedom to be able to sell the gas back to the wholesale market is a unique quality of the contract and enables the power station owner to maximise profit margins on the gas that has to be bought under the terms of the deal. This is one of several reasons why the transaction is so different to the less advantageous 'spark spread' contracts that are traded in the gas and electrical power markets in the US.' He also adds that: 'The dash for gas by power companies and the increasing downward pressure exerted on electricity prices through industry regulation has stimulated demand for our type of contract both in the UK and across Europe.'

The wholesale price of a megawatt hour of electricity is currently around £26 and around 12 pence to 13 pence per therm of gas.

South American regasification terminal first

Shell Global Solutions and Cryogaz Technologies – a joint venture between Technigaz (owned by Bouyges Offshore) and Gaz de France subsidiary Sofregaz – have announced plans to cooperate in the development of fast-track, low cost LNG and LPG terminal projects.

The Suape LNG import terminal near Recife in northeast Brazil will be the first project to be carried out. The facility, which will serve the needs of Petrobras and Shell Brazil, is said to be South America's first regasification terminal.

In Brief

US fleet card company Fuelman/Gascard *Network is understood to have agreed a deal under which its 20,000-plus customers will be able to access the company's fuel management services and purchase fuel from 1,500 Arco service stations in California, Arizona, Washington, Utah and Nevada.*

Middle East

It is reported that the Basra oil refinery *in Iraq may have been damaged during US and UK military strikes in December 1998. The facility is capable of handling 126,000 b/d of crude, 36% of the country's total daily refining capacity; much of its output is thought to be smuggled into Turkey in violation of the UN programme.*

Oman is understood to have agreed to *supply Enron's Dabhol power plant in India with 1.6mn t/y of LNG over 20 years beginning in 2001.*

Russia & Central Asia

Yukos and Transneft are proposing to *expand oil export capacity from Russia, according to United Financial Group's* Russia Morning Comment. *Plans include the construction of a new oil export terminal in north Russia on the Gulf of Finland, and the reversal of the Adria line which currently delivers oil to Hungary from the Mediterranean. Transneft would be responsible for financing the projects, while Yukos will supply the oil.*

First oil is reported to have flowed *through the Baku–Supsa pipeline linking Azerbaijan and Georgia. The western export route for the AIOC-operated Azeri, Chirag and Guneshli fields is expected to be fully operational early 1999.*

US company Unocal is understood to *have abandoned plans to build a \$2bn gas pipeline linking the eastern Caspian Sea in Turkmenistan with Pakistan via war-torn Afghanistan due to budget constraints and low oil prices.*

Mobil, Chevron and Shell are reported *to have agreed a 15-month study of the commercial viability of building parallel east–west oil and gas pipelines linking western Kazakhstan to Baku in Azerbaijan via the Caspian Sea.*

NEWS Downstream

Thompson tanker for the new millennium

Shell UK recently took delivery of a Thompson Carmichael ADR 5000 tanker at its Stanlow terminal in Ellesmere Port.

The new 'flagship' petroleum tanker range, launched by Thompson in 1998, is said to comply with European ADR and proposed CEN regulations and claimed to offer a 'very competitive' tareweight (see *Petroleum Review*, November 1998).

November UK fuel prices

	Pence per litre
Diesel	
Lowest: Middlesb'ro	63.15
Highest: Oban	69.69
National average	65.95
Unleaded petrol	
Lowest: Bradford	62.93
Highest: Oban	68.60
National average	65.31
Four-star petrol	
Lowest: London	67.84
Highest: Oban	75.90
National average	70.88

Source: *PHH Allstar Fuel Report*

Middle East storage first

Van Ommeren ENOC Fujairah has opened what is said to be the first independent tank storage facility for oil products and bulk chemicals to be located in Fujairah in the United Arab Emirates. At the beginning of December 1998, the Danish tanker Torm Gyda discharged the first 45,000 tonnes of gasoline into the 511,000 bn cm capacity storage terminal.

Van Ommeren designed and built the facility and will act as operator. The terminal will be used to consolidate exports from the Gulf region and serve as a break of bulk centre for distributions to neighbouring markets such as India, Pakistan and East Africa. Van Ommeren currently operates a worldwide network of 56 tank terminals with a total storage capacity of 15.3mn cm.

In Brief

Asia-Pacific

The West Natuna Group (Premier Oil *Natuna Sea, operator – block A; Conoco Indonesia, operator – block B; Gulf Resources (Kakap), operator – Kakap) is to supply 325mn cfld of natural gas to Singapore over a 22-year period beginning in 2001. Approximately 2.5tn cf of total gas reserves are to be delivered via a 650-km subsea pipeline system.*

Thai state-owned petroleum authority, *PTT, is understood to be planning to merge its downstream oil operations with its refining business Thai Oil and to float shares in the new company.*

Enron Corporation of the US is *reported to have invested $300mn in a 50:50 gas import and distribution joint venture with South Korean oil refiner SK Corporation.*

Japan Petroleum Exploration, Itochu *Corporation, Marubeni Corporation and Exxon are reported to be jointly studying the feasibility of a natural gas pipeline linking Sakhalin and Japan.*

Latin America

Italian oil company Agip is reported to *have opened its first service station in Brazil in the city of Sao Paulo.*

Mexico is understood to be planning *to open access to Pemex's gas pipeline network by the 2H1999. Details of the tariff agreement have yet to be decided.*

UK Deliveries into Consumption (tonnes)

Products	†Nov 1997	*Nov 1998	†Jan–Nov 1997	*Jan–Nov 1998	% Change
Naphtha/LDF	288,847	257,351	2,020,400	2,598,220	29
ATF – Kerosene	663,928	704,661	7,750,844	8,342,392	8
Petrol	1,795,925	1,778,512	20,357,865	19,887,213	–2
of which unleaded	1,332,673	1,434,619	14,593,016	15,563,273	7
of which Super unleaded	38,194	31,997	474,674	376,366	–21
Premium unleaded	1,294,479	1,402,622	14,118,342	15,186,907	8
Burning Oil	278,165	335,958	2,882,494	3,138,198	9
Automotive Diesel	1,263,558	1,317,246	13,752,683	13,849,157	1
Gas/Diesel Oil	587,972	647,327	6,629,726	6,613,755	0
Fuel Oil	263,520	323,916	3,542,983	2,599,926	–27
Lubricating Oil	68,803	64,512	807,714	753,768	–7
Other Products	653,618	649,068	7,895,126	7,433,863	–6
Total above	5,864,336	6,078,551	65,639,835	65,216,492	–1
Refinery Consumption	571,132	488,698	5,994,580	5,908,555	–1
Total all products	6,435,468	6,567,249	71,634,415	71,125,047	–1

† Revised with adjustments *preliminary

Assessing risks and uncertainties in project developments

Continuing low oil prices means that it has become more important than ever before to assess project risk as accurately and objectively as possible when evaluating a field prospect. *Trevor Ridley,* Petroleum Engineering Adviser to BHP Petroleum, describes an approach to analysing risks and uncertainties to produce risk profiles that provide an objective approach to project evaluation. *Petroleum Review* asked him a number of questions about the way he evaluated project risk for BHP Petroleum.

Q: Where does your interest in risk management have its roots?

A: I was working in South Africa for Soekor, the state-owned upstream oil company. We had a small field offshore that we wanted to develop, but there were severe technical uncertainties and many non-technical issues threatening our ability to justify the project. I was working with some talented individuals who were able to harness these uncertainties in a statistical sense, which gave us the tool we needed to manage the risk of the project. This is described in a paper written by three of us who worked together on that project.[1]

The outcome of this effort was that we received approval to develop the field. Happily, its subsequent performance has justified that decision to proceed with development.

The manner in which we managed the project's risk was a key factor in securing approval to proceed with development. The methodology is surely applicable to other projects, which is why I like to talk about it with other people.

Q: What made your handling of risk different to other companies' approaches?

A: I don't claim to know how other companies manage their project risks. Most people that I have spoken to are in fact confident that they manage risk satisfactorily. On close examination, however, I find often that we are talking at cross-purposes!

Q: Why do you say that?

A: In my world, 'risk' is a property of the project's deliverables whereas 'uncertainty' is a property of the components that are combined to create that project. For instance, my project may be intended to deliver a certain NPV [net present value], in which case its 'risk' relates solely to the probability of achieving that NPV. In order to implement my project, I may be planning to develop a certain quantity of reserves at a given capital cost – these are its components and they have 'uncertain' values. I control the 'risk' associated with my NPV by managing the 'uncertainty' of these components.

I find that most people, in describing their 'risk' management, are referring more to the 'uncertainties' of the project's individual components rather than their combined impact on the project itself, as measured for example by its NPV.

Q: Isn't this just semantics?

A: Until you get used to the distinction I have derived between 'risk' and 'uncertainty', it may seem like semantics. My point is that 'risk' is the consequence of combining a project's component 'uncertainties'. Simply determining the potential maximum capital cost, for instance, does not determine the 'risk' of the project – unless the sole purpose of the project is to spend a given capital sum!

Q: Are you saying, in this example, that companies don't properly evaluate the impact of a capital overrun on a project's economics?

A: Re-running a project's economics with upside and downside costs will certainly produce calculations of the project's upside and downside economic performance. But I hesitate to equate this to calculation of the project's upside and downside 'risk' unless it also tells me the probability of each of these economic outcomes being realised. And to do this properly requires that the impact of all the project's other 'uncertainties', such as reserves and oil price, for example, be considered at the same time.

Q: Isn't an upside and downside view of a project's economics sufficient?

A: Well, I have found that an objective approach to analysing the 'risk' of a project helps eliminate much of the subjective passion that can accompany evaluation of a marginal project. The impact of a particular reservoir uncertainty, for instance, can be included in the analysis to the level of detail necessary to convince a dubious manager that his concerns have been properly addressed. And even though there may be significant downside uncertainties, the compensatory effect of the components' upside uncertainties can help keep the project's overall perspective in balance. It helps ensure that the appropriate decision of whether or not to proceed with the project is taken.

Q: How do you actually assess the risk of a project?

A: The first requirement is to establish what parameters will be used to measure the attractiveness of the project. To illustrate the principles, let's assume that our project will be judged solely by its NPV. (In reality, there will likely be several parameters that together will form the basis for the decision on whether or not to proceed with the project.) The next step is to establish exactly how you intend to determine the parameters' values. In our case of NPV, for example, we will need a cash flow forecast. To make a cash flow forecast, we will need a capex schedule, a production forecast, a price forecast and an opex forecast. If we wish to determine NPV after tax, we will also need to calculate the tax payable in each production period.

To assess the probability of occurrence of the resulting NPV, it will be necessary to repeat its calculation many times, typically a thousand or more depending on the complexity of the underlying capex, opex, production and price forecasts. Each of these forecasts will be generated from a random sampling of the project's 'uncertain' components. The resulting spread of NPV, in this case, will define the probability that a particular value of NPV will be achieved.

Q: Yes, but how do you generate those underlying forecasts so that they are consistent with the uncertainties of their components?

A: The capex cost and schedule are reasonably straightforward and there is commercial software available that can help the task. But, from first principles, you can perhaps imagine identifying the various components of the capex and placing simple upside and downside costs around each of these. Or, we can take a more sophisticated approach and estimate their costs from the price of steel, the cost of labour and the man-hours required to fabricate the components. Firing up the random number generator, we can then estimate the cost of each component independently and combine these estimates to create the overall capex forecast. Assuming we do this in a spreadsheet, possibly with the assistance of commercial software such as @Risk or Crystal Ball, we can then paste the capex forecast directly into our economics spreadsheet as input into the cash flow profile.

Q: I can see how you can use a similar approach to produce opex and oil price forecasts but how do you generate the production profile so that it is consistent with reservoir-related uncertainties?

A: This is certainly the trickiest task! I find it helpful to tackle it in stages, which I will describe backwards.

If I have an estimate of recoverable oil volume, I can convert this to a production profile by assuming that part of that volume will be produced under plateau conditions and that the balance will be produced under some form of decline. If I know how many wells are available initially, their individual production rates and the maximum capacity of the facilities, I can estimate (with some simplifying assumptions) both the plateau production rate and its likely duration. This defines the volume produced at plateau, which means the balance of oil is produced under decline. If I can assume an exponential decline, it is mathematically easy to allocate that remaining volume to a production forecast.

The trick then is to estimate the recoverable oil volume. I like to split this into two random determinations, for oil in place and recovery factor, respectively. Oil in place is relatively easy to establish, and is often already available in the form of P90/P50/P10 estimates, so I'll concentrate on discussing the recovery factor.

The simplest approach is to establish an appropriate distribution of recovery factor whose parameters have been determined from material balance or more sophisticated reservoir engineering studies. The complexity of the reservoir will dictate the sophistication necessary for these studies.

It is as complicated as you wish (or need) to make it. The key is to ensure that the statistical model of recovery factor is calibrated against the reservoir model over the range of possible values for the various uncertainties being considered.

Q: And are there any further considerations?

A: Another key point is that there must be consistency between the forecasts underlying the cash flow calculation. An obvious example is the number of wells, which affects the capex forecast, the production forecast and the opex forecast. It is possible that the number of wells could be an output from the production forecast 'module' (for example, if a dry hole were assumed drilled in a particular area of the field, it is unlikely that a second well would be drilled in that same area), in which case the capex and opex forecasts would be dependent on the results of that production forecast.

Note also that the 'reserves' for each iteration will be dependent not only on the (technically) recoverable oil volume but also on the opex assumption. In this sense, a probabilistic distribution of 'reserves' becomes an output from the stochastic process.

Q: Any other key points?

A: I'd like to make just two observations. First, this approach to risk assessment allows different development scenarios to be compared over their full ranges of probability. It might transpire that Scenario 'A' is more attractive than Scenario 'B' at a P90 level of confidence (in terms of NPV, for example) but that Scenario 'B' becomes more attractive at a P50 level of confidence and beyond. Different companies may have different views about the appropriate confidence level at which the scenarios should be compared, but this approach to describing the project's risk will help provide a rational basis for debate on the issue.

Allied to this point is the observation that the entire stochastic simulation process I have described here should be applied to one development scenario at a time. This then provides the basis for comparing those scenarios and deciding which is the most appropriate for implementation. If the development scenario itself (for example, water injection or gas injection) is one of the uncertainties, the results become somewhat meaningless as far as decision-making is concerned.

Q: You've talked about assessing project risk, but how does this help you to manage that risk?

A: Once you have set up a model to determine the project's risk, you also have a tool to evaluate the impact on that risk of managing the project's underlying uncertainties. So, for example, if you were able to do something that resulted in less uncertainty over recovery factor, by plugging your new view on recovery into the model you will receive an updated view on the risk of the project. In general, the approach to each uncertainty should be either doing something to justify 'improving' its value, such as finding a way to reduce capex or to increase recovery factor, or to reduce the uncertainty surrounding its value. Collapsing an uncertainty will always lift the P90 view of overall project risk to some extent.

To help focus on the uncertainties most influencing the project's risk, it is useful to prepare a spider chart – this will identify those uncertainties most likely to influence the outcome of the project and therefore most appropriate for attention.

Q: Can you summarise the process that you advocate for risk management?

A: The first step is to establish the parameters by which the project is to be judged. These are likely to be economic parameters such as NPV, rate of return and so on. The output of the process will be probability distributions for each of these parameters.

The next step is to prepare a spreadsheet in which these parameters are calculated. Typically, this will involve a determination of cash flow from which the required economic parameters can be calculated.

The underlying components of the cash flow forecast (that is, the capex schedule, the production forecast, the opex schedule and the price forecast) are developed from the 'uncertainties' that comprise the project. This is easier said than done and can be quite complex. I use macros to determine each of these forecasts and to paste them into the cash flow spreadsheet.

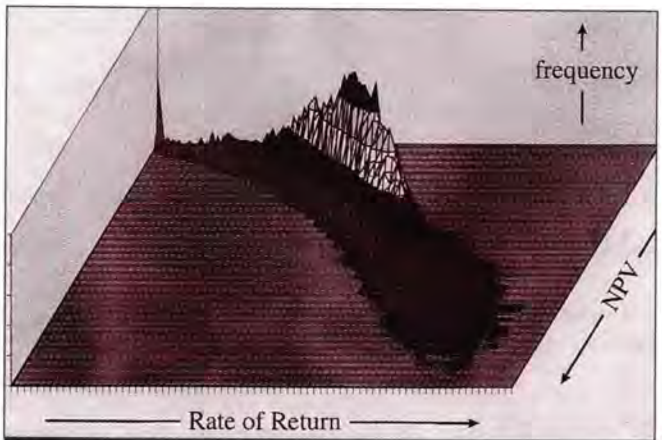
It is necessary for each of the project's 'uncertainties' to be described in the spreadsheet. This is easily done using an add-in such as @Risk or Crystal Ball, but it can also be done from first principles using macros. When the capex schedule is determined, for instance, its macro will interrogate the relevant uncertainties to select the cost and time data it needs to build the schedule. Similar principles apply to the creation of the other components of the cash flow forecast.

Once the cash flow forecast is in place, it is possible to calculate the parameters that are being used to evaluate the project. This process needs to be repeated many times (thousands, typically), each repetition invoking a new set of values from the bank of 'uncertainties' and, thus, a new cash flow forecast. Again, it is helpful (though not necessary) to use an add-in such as @Risk or Crystal Ball to capture the results of each repetition and to present them in a useful format.

You will find that the distribution of each output parameter settles down quickly in terms of its value associated with various levels of confidence, say after a thousand or so repetitions. But a graph of that distribution may look very ragged and require tens of thousands of repetitions to make it look smooth and pretty!

The most challenging part of the process is to capture the reservoir uncertainties and convert them into a production forecast. In order to be able to run

continued on p49 ...



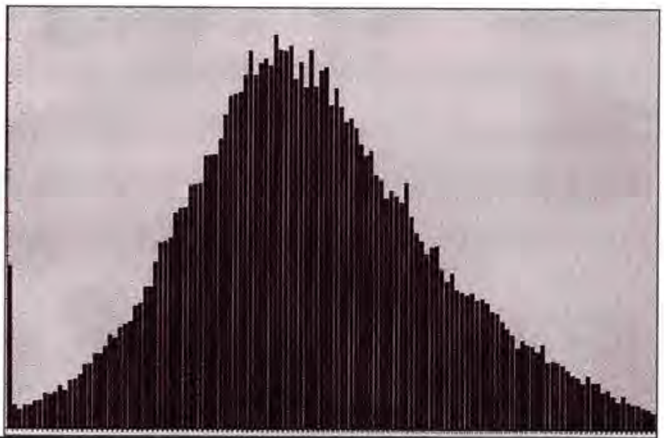


Figure 1 (left): 3D probability mapping showing the interaction of the projects, NPV and Rate of Return. The most likely outcome of the project is represented by the banded area in the centre. The downside of the project is represented by a thin ridge in the top left-hand corner and the upside is represented by the broad area in the bottom right-hand corner. It is the result of 50,000 iterations, but the general shape of the distribution stabilised after 10,000 iterations.

Figure 2 (right): The conventional (2D) representation of a project's NPV distribution. It is the 'shadow' of the distribution in Figure 1 projected onto the left-hand wall of that figure.

Dispute resolution – sorting out the legal loopholes

In December 1998, the Institute of Petroleum hosted a conference on 'Dispute Resolution in the International Oil and Gas Industries'. *Petroleum Review* looks at the types of disputes common in the petroleum sector, both at home and abroad.

The day-shift at a Middle East petrochemicals plant had just gone home from work when, without warning, disaster struck – a liquid propane storage tank split in half. The contents, 35,000 cm of highly flammable fuel, spilled out and burst into a huge fireball, killing seven.

In addition to the tragedy of the deaths, the plant was completely destroyed. The cost of replacing the facility and covering the loss of production was estimated at over £500mn. The Middle East government that owned the plant felt it was entitled to compensation from the engineering firm that had built the propane tank, and called upon the London-based law firm Herbert Smith for help.

Ted Greeno is the Head of Energy Litigation at Herbert Smith. 'There is an overall growth in the amount of litigation and arbitration in the oil and gas industry for a number of reasons,' notes the solicitor. 'The pressure on prices and margins has meant that companies are more inclined to fight over smaller sums. There is also more competitiveness in the marketplace, and companies are more aggressive. And finally, American attitudes toward litigation are finding their way to the UK.'

Types of dispute

Petroleum industry disputes fall into four main areas, explains Paul Smith, one of approximately 100 solicitors based in the UK who specialise in the energy sector. 'The major areas include gas contracts, oil trading, construction, and unitisation.'

Gas contract disputes arise when a gas contract is set with a floor price, and the gas market price goes down below the contract price. 'Many of the contracts are relics of the days when British Gas held monopoly power to buy gas under a "life-of-field" contract, in which BG contracted to take whatever was produced from an offshore field,' says Smith. 'The contracts were designed to run for 25 to 30 years.'

The contracts did not predict deregulation, the loss of monopoly powers, and the ability to buy gas at spot prices on a commodity market, however. 'In the mid-1990s, gas prices went down below the contract floor prices,' says Smith. 'In the law, there is no relief if the buyer entered into a bad commercial bargain.' The only way out was to find a loophole that could be exploited to negate the agreement. 'The lawyers then started going through the contracts with a fine-toothed comb.'

International oil trading creates thousands of contracts that detail the origin, quantity, delivery dates and quality of crude from around the world. These multi-million dollar contracts are traded on commodity markets on a daily basis, and any given contract may pass through 30 hands before its expiry. Should a complication over payment or details compromise any given contract, however, it quickly draws a wide net of concerned parties into a dispute over responsibility. 'It's like a daisy-chain, and when one loop snaps, the entire chain becomes unravelled,' says Smith.

Construction contract disputes arise when anything from a tiny valve in a pipeline to a huge offshore production platform doesn't do what it was designed to do, or suffers a catastrophic failure. 'Let's say an offshore gas field goes down, and it can't deliver gas,' says Greeno. 'Who is responsible? A bad storm that suspends production is *force majeure* (or act of God), but a fire on a platform that stops production could be regarded as something that could have been avoided.'

Unitisation disputes arise when a discovered field falls between two E&P licenses. In order to avoid two competing companies from sucking as much oil and gas out of the field from their respective licenses, government regulations stipulate that a field must be exploited using the most efficient engineering practices. The field is thus 'unitised', and operated by one company, and a proportion of the output assigned to each owner, based upon the percentage of the field within their license.

The proportion of the field assigned is based upon preliminary data, such as seismic and exploration wells. As the field is further exploited, however, subsequent data can occasionally compel one of the partners to seek a larger percentage of the field's production through a process known as redetermination. 'There is normally a clause in the unitisation agreement that either side can initiate a redetermination within the first 12 months of production,' says Smith. When the two companies cannot subsequently agree on who-gets-what, a dispute arises.

Fortunately, the vast majority of disputes within the petroleum industry are settled informally. 'Hundreds of contract disputes arise every year, and 90% never get to the courts or arbitration,' says Smith. Part of the reason is that, unlike North America, where plaintiffs tend to file lawsuits at the drop of a Stetson, British parties are still much less partial to law courts. 'When a dispute arises, the first thing we do is get out the contract and define the issues involved,' says Smith. 'Is right on our side? Is right not on our side? Normally, everything can be resolved commercially, with a payment to one party or another.'

Resolution

When they can't be settled in-house, the next step is to seek out the opinion of a speciality law firm in the City, to discuss the merits and drawbacks of pursuing a dispute. 'If you're needlessly aggressive, you get a bad reputation,' says Greeno. 'On the other hand, if you give in too readily, you can get a reputation as a patsy.'

If a decision is made to pursue a dispute, the next step is to decide the venue. In the UK, there are three main forums: expert determination, arbitration, and the High Court.

As the name implies, expert determination usually involves appointing a specialised professional to adjudicate a dispute that involves technical matters, such as the quality of petroleum being produced, or the size of a field. 'Experts are very useful when there is a disagreement over unitisation during redetermination, for instance,' says Smith.

The expert examines all available data and comes to an independent decision. 'The advantages of the expert process are that it normally takes 30 to 60 days, and can cost around £10,000 to £50,000,' says Smith. 'Also, his decision cannot be appealed.'

'An expert can be held liable if he is negligent,' cautions Greeno. 'On the other hand, High Court judges and arbitrators cannot be held negligent.'

Arbitration, governed by the Arbitration Act of 1996, is specifically designed to be incorporated into contracts through a clause. Theoretically, anyone can be an arbitrator. In practice, however, professionals such as engineers, solicitors and accountants who specialise in arbitration are chosen, depending on the nature of the dispute. 'If the two parties cannot agree upon an arbitrator within 21 days, then the society governing the profession, such as the Institute of Chartered Accountants, will appoint one,' says Smith.

Although arbitration cases can take up to one year and be just as expensive as the High Court, they have the advantage of being confidential, notes Smith. 'The decisions are also very difficult to appeal against.'

Like High Court cases, arbitration is relatively rare in the UK oil industry, with only one or two arising each year. Greeno recalls a case in 1981, which involved a three-month-term crude oil contract that British National Oil Company (BNOC) had written to buy oil from a North Sea producer. 'The contract contained a review clause if there was significant movement in price,' says Greeno. 'When the price rose, the producer wanted the price indexed to similar crudes in North African oil, while BNOC wanted the price change tied to similar crudes in the North Sea.'

The dispute went to arbitration, and the arbitrator decided for BNOC, linking the price increase to North Sea oil. 'It was amicably resolved quickly, and efficiently,' says Greeno. 'The entire process took six weeks, from start to finish.'

The High Court handles serious criminal and civil cases. In order to initiate a law suit, the plaintiff issues a proceeding in the High Court. The named defendant then files a defence. The lawsuit passes through a court administration stage where witness statements and evidence are gathered. The proceeding then goes before a High Court judge, who gives a judgment.

A High Court case can take up to two years, and can cost more than £1mn in legal fees, and is still subject to appeal in the Court of Appeal (and, in exceptional cases, the House of Lords). The level of money at stake is often in the order of hundreds of millions of pounds.

CATS vs Enron is a recent, high-profile case. In the early 1990s, American firm Enron entered into a take-or-pay agreement with a consortium of oil companies (led by Phillips, BG and Agip), to buy a large quantity of gas from J-block in the North Sea.

New infrastructure had to be built in order to get the gas to land. Amoco, Amerada Hess, BG, Phillips, Agip and Fina, under the Central Area Transmission System (CATS) consortium, proceeded to build a gas line and a landing terminal. Enron entered into a send-or-pay agreement with CATS to help finance the cost of construction. Part of the agreement stipulated that, when the pipeline and terminal were built and ready, CATS had to serve a commencement date notice. CATS did so in 1993.

In 1995, gas market prices fell, making Enron's take-or-pay contract less profitable. Enron argued that the commencement-date notice, which was served on time, was not a valid notice due to technical reasons, and that the send-or-pay contract was therefore terminated. Further, says Greeno, 'without a send-or-pay contract, Enron asserted, the take-or-pay contract with J-block was also void.'

CATS, which had spent around £300mn on the infrastructure, disagreed, and called in Greeno. 'CATS issued a writ demanding that they receive £80mn under the send-or-pay contract,' says the solicitor. 'In their defence, Enron sought to reclaim approximately £50mn that they had already paid.'

The case went to the High Court on November 1996, and ran for five months. In the end, the judge ruled in favour of CATS, awarding it the outstanding amount under the send-or-pay contract of £80mn, and dismissed Enron's claim for £50mn. The day before the judge issued his ruling in favour of CATS, Enron renegotiated and signed a new take-or-pay contract with the J-block owners. The case is still in the appeals court.

One further venue is available for dispute resolution: international arbitration. When a UK company signs a production sharing agreement with a national petroleum company in a developing country, for instance, many are concerned about redress should the contract be unilaterally altered by the host country. 'In the case of nationalisation, they want compensation to be decided by a court outside of the host country,' says Smith.

There are several bodies willing to arbitrate international cases, including the London Court of International Arbitration and the International Chamber of Commerce. 'An arbitration clause is written into the contract,' says Smith. 'It usually stipulates which body to use, where the case will be held, and what language will be used.'

Minimising disputes

For those wishing to minimise disputes, Smith recommends taking time and effort to draft a sound agreement in the first place. 'A good contract should have clarity and completeness.'

Also, make sure there's something in it for both sides. 'It's like building an extension on your house,' explains Smith. 'If you put the screws down on the builder too tight, then you're going to get disputes. On the other hand, if you leave room for reasonable profit, you'll get fewer hassles.'

When a problem arises, think about all possible outcomes before you act. 'Taking a case to the High Court can be expensive,' says Smith. 'On the other hand, £5mn in legal costs is relatively cheap when £100mn is at stake.'

Look at the larger picture. 'E&P is one of the few industries where you work in teams,' says Smith. 'If you sue a partner this year, will you be invited next year to participate in a joint venture?'

Trends

Over the next decade, Smith foresees a rise in lawsuits instigated by, and on behalf of, the public due to environmental damage. 'If they can pin a deteriorating environment on an oil company, they will.' He also predicts that government Health and Safety regulations will get more onerous. 'The effect will be an increase in corporate insurance premiums.'

One factor that may help induce lawsuits is a recent change in the way solicitors can charge for their services. 'In a bid to reduce the costs of legal aid, solicitors are now allowed to take on a case on a conditional basis – no win, no fee,' says Greeno. 'If they do win, they can bill up to twice their normal fee.'

Although the UK does not suffer the same blizzard of writs that the US does, Greeno predicts that the shift to a conditional fee basis will create a more litigious society. 'It's just a matter of time.'

A compass to navigate troubled waters

Knowledge Management has become a key industry term alongside phrases such as Lifetime Learning, Risk Management and Safety Management. *Alan Hocking* of Arthur Andersen explains Knowledge Management and how it can benefit the industry. IP Week delegates can also join the forthcoming Knowledge Management workshop to be held during IP Week, Tuesday 16 February 1999 at the Dorchester Hotel.

Volatile, challenging and changing. These adjectives have always applied to the petroleum industry. Since the oil crises of the 1970s, we have been trying to learn ways to make our businesses more robust and profitable in turbulent times. In today's climate of low oil prices and structural change, approaches that build our capacity to learn, increase efficiency and exploit our potential are more welcome than ever before.

Though no-one in the field claims it to be a panacea, the fast-developing area of Knowledge Management is one approach to be found on the corporate agenda.

With its roots in the consultancy industry, concerns about its practical application and value in other sectors may have been justified in the past. People have also stumbled over the many definitions. Its essence lies in the practice of protecting, developing and applying business knowledge in pursuit of strategic priorities. Broadly, knowledge itself can be embedded in anything from innovative business practices, technology patents and corporate databases to the minds and gut feel of industry experts. The difficulty is in understanding how this knowledge can be developed and managed in ways that contribute directly to business value.

A practical approach

Implementation of Knowledge Management practices has recently gained pace across a broad range of industries and a practical understanding of its application and benefits need not be elusive. Executives can now learn from the experiences of large organisations, including those in the oil and gas industry, who are beginning to reap rewards from practical Knowledge Management approaches.

For example, the Exploration and Production division of Shell International identified a key knowledge requirement as the efficient and effective evaluation of field prospects. Shell set up a team, evaluating a real bid prospect, as a 'laboratory' in which to experiment and develop this new knowledge. For the first time, geologists, well engineers and economists were co-located in one space to aid collaboration; group-ware technology networked the team with partners overseas; and an action-learning facilitator focused on the team's effectiveness and the capture of their experiences in a Learning History.

'Executives can now learn from large organisations who are beginning to reap rewards from practical Knowledge Management approaches.'

The result? An estimated 40% reduction in time to reach the bid decision and a 14% reduction in the total field study cost. By publishing the experience and lessons learned on the web-based Open Learning Centre, the benefits of these new ways of working can now be replicated by any team.

The strategy at Enterprise Oil highlights a different knowledge imperative. Exploiting the full potential of its field assets requires an expert approach to drilling deepwater prospects, exploiting fractured reservoirs and producing hydrocarbons from complex turbidite structures. By establishing international 'Communities of Practice' that meet physically and virtually, thinly-spread experts have the forum and tools to collaborate on these priority challenges. The knowledge management team at Enterprise now has a documented, practical approach for mobilising and supporting future communities as business priorities unfold.

In the downstream industry, the search to boost poor margins has led some companies to develop knowledge to compete in entirely new businesses. Shell recently had the confidence to compete on one of London's busiest high streets by opening a convenience store and bakery on the Strand, several miles from the city's nearest petrol pump. This could never have happened two years ago. The difference? A new, pan-European business structure promoted collaboration between the UK, Portugal and Scandinavia, and recruitment from the supermarket sector heightened the learning curve. In the future the Shell-wide web will give all Shell companies access to what is being learned from this retail experiment.

Lessons learned

Through own internal experience and work with these companies and others, Arthur Andersen has distilled a number of lessons that can constitute the foundation of any company's approach to Knowledge Management:

- Primarily, Knowledge Management activities must be tied to business strategy: organisations must identify what they really need to know and do.
- Communities then need to be built linking individuals or groups who share common business imperatives.
- Subsequently, frameworks must be developed to facilitate interaction between community members, and an infrastructure that supports Knowledge Management on a continuous basis must be maintained.
- Finally, Knowledge Management must not be viewed as just an information technology solution. It requires the integration of strategic, process, cultural and technological considerations.

Arthur Andersen Knowledge Services invites IP week delegates to attend a workshop to explore these issues further and to share insights and case examples. For further details on the workshop see P 42.

Caspian oil and gas flows west but doubts remain

For the development of Caspian energy, 1999 is likely to prove a crucial year. It is a year in which significant progress should be made in getting both Caspian oil and gas to market, but it is also likely to be a year in which the scaling down of projects is just as noteworthy, writes *John Roberts*.

On the production side, matters are not looking too good. Although the first – and biggest – of the Caspian consortia is now steadily increasing output and has indeed begun exporting crude oil by two separate pipelines, the next three consortia have all reported disappointing results from well-drilling. Indeed, in the case of the second consortium to reach an agreement in Azerbaijan, the Caspian International Petroleum Company (Cipco), the results have been so poor that the company has indicated its intention to pull out altogether, a move which was expected to be implemented as *Petroleum Review* went to press. However, the BP/Statoil consortium's first well on the Shah Deniz structure 70 km east of Baku will be completed in February. Reserves on the acreage have been estimated at up to 2.4bn boe.

Cipco's disappointment was a sign that in one case, at least, the Caspian has failed to live up to the early hype. When Cipco, led by US company Pennzoil, signed its agreement in 1995, reserve estimates for its Karabakh concession were put at 100mn tonnes of oil and 65mn tonnes of gas. By the time it was ready to quit Azerbaijan, Cipco President James Tilley was saying that the current estimate of recoverable reserves was 25mn tonnes, whereas a reserve base of at least 40mn tonnes would have been necessary for the project to make commercial sense.

The failure has not created a sense of total despondency in the Caspian oil community, since there are always bound to be some dry holes. But it punctured the myth that all Azerbaijani wells were always successful, and reminded the community of the fact that, whereas the first of the giant consortia – the BP/Amoco-led Azerbaijan International Operating Company (AIOC) – took over an operation in a proven oil field discovered in the Soviet era, the subsequent 13 offshore concessions were for structures believed to possess oil, but which had not actually been proven by drilling.

AIOC announced in late 1998 that it was delaying the implementation of the second stage of its development programme, intended to take production from around 400,000 b/d to 800,000 b/d. But, since at the time it was only producing around 80,000 b/d and was looking to raise this to around 100,000 b/d by the start of 1999, the delayed start to a second phase which was anyway conditional on the availability of new export facilities did not seem particularly threatening.

What was more important was the progress, albeit bumpy, which AIOC was able to make in developing a multiple export pipeline system for its so-called 'early oil'. Particularly important, the implications this would have on its requirement to make a formal recommendation to the Azerbaijani authorities for a so-called 'Main Export Pipeline' (MEP) capable of handling at least 500,000 b/d and expected, in practice, to be capable of handling 1mn b/d.

Novorossiysk exports

In late 1997, AIOC began exporting crude oil via an existing pipeline to the Russian Black Sea port of Novorossiysk which it had repaired on its own side of the Azeri-Russian border but remained unsure concerning the extent of renovations on the Russian side. In consequence, although the line's baseplate capacity is supposed to be 180,000 b/d and actual throughput had been expected to reach around 100,000 b/d, in practice it chose to limit pumping to a maximum 50,000 b/d during 1998.

Throughout the year, AIOC also faced problems on the second of its 'early oil' lines linking Baku to the Georgian Black Sea port of Supsa. In effect, instead of being able to utilise long stretches of existing line, AIOC and its Georgian affiliate, the Georgian Pipeline Company, found itself having to relay new pipe over some 90% of the line's 926-km length. The costs soared from $236mn to $590mn. This caused friction with the Azerbaijani authorities which stood to suffer from a severe delay in revenues, since the agreement with AIOC provides for the consortium to recoup its expenses before paying royalties to the State Oil Company of Azerbaijan (Socar) and the Azerbaijani government.

However, on 10 December 1998, oil did start to flow into the pipeline and on 8 January 1999 that oil crossed the Georgian border – even though not all the work on the Georgian pipeline seemed to have been completed. First shipments from the Georgian coast are scheduled to formally start on 1 April 1999.

The problems of developing the Baku-Supsa line may come to be seen as a blessing in disguise. Within a few months of the October 1995 agreement on the two-pipeline approach, AIOC realised that so much work would have to be done on the Supsa line that it would be sensible to make a limited increase in early investment costs in order to ensure that the line could be smoothly expanded to around 200,000 b/d. Such an expansion would be possible through the provision of additional pumping stations. (AIOC directly controls the Baku-Supsa line whereas most of the Novorossiysk line is operated by Russia's Transneft.)

With the discovery in 1997/8 that instead of replacing half the existing Baku-Supsa line, almost all of it would have to be brand new, it appears that the potential for future capacity increases has again risen. It now seems feasible to assume that what is now AIOC's existing line will eventually be capable of carrying at least 300,000 b/d, and, perhaps, a good deal more.

Delayed decision

This changes the picture for potential export line projects from Azerbaijan – for Caspian oil development in general and Azerbaijani oil development in particular. In terms of export pipelines, it delays the requirement for a MEP, whilst simultaneously establishing the utility and practicality of the Baku-Supsa route. Moreover, since for a year or two it seems likely that a line intended essentially to carry just a little early oil may possess spare capacity almost from start-up, the prospect exists for either onshore Azerbaijani oil production to be exported via the new line or, more likely, for oil to be tankered in from oil producers in Kazakhstan which are currently hemmed in by Russian restrictions on Kazakh oil exports via the Russian pipeline system.

Chevron, which is developing the giant Kazakh oilfield at Tengiz, is already probing the advantages of the Azerbaijan-Georgian corridor. It has built its own terminal for offloading Tengiz crude in Azerbaijan and loading it on to rail cars for shipment by train to the Georgian seaport of Poti. In 1998 it also began developing plans to rehabilitate other former pipelines which essentially follow the same Kura Valley route into Georgia from Azerbaijan as the Baku-Supsa line, so that it could reduce its dependence on export routes via Russia.

Policy reversal

It may well have been Chevron's policy reversal in 1996 – when it abandoned its assumption that Russia would prove an amenable partner for Kazakh oil exports and opted for a strategy of exporting oil by any method that might prove practicable – that finally convinced the Russians that they would have to remove the final barriers to the other great pipeline project westwards, the Caspian Pipeline Consortium's plans for a line from Tengiz to Novorossiysk, or else face the prospect that the CPC project might simply miss its window of opportunity.

CPC was founded in 1993 as a consortium comprising the governments, or their appointed representatives, of Russia, Kazakhstan and Oman, with the latter inspiring the project and gaining its stake because it had helped facilitate the conclusion of the Kazakhstan state negotiations with Chevron for development of Tengiz. But a government-owned structure proved incapable of getting the project started and in 1996-7, the CPC was extensively restructured, with the Omani share diluted from 33.3% to just 7% and private companies (all involved in developing energy resources in Kazakhstan) securing a 50% stake. The original CPC goals for a two-phase project that would open a line with a 28.5mn-t/y capacity and then expand it to 67mn t/y, were maintained. But when, in November 1998, the final agreement was reached on actual expenditures required to get physical construction of the line under way, it was clear that limitations on phase one expenditure would render implementation of the second phase extraordinarily expensive. So, while it does now look as if, at last, a 1,500-km pipeline from Tengiz to a new terminal near Novorossiysk will be built, it is also clear that it will be a considerably scaled-down project.

Thus 1999 will see the oil companies in Kazakhstan look ever more closely at options for trans-Caspian shipping, and eventually a trans-Caspian pipeline, so that they can also look to take advantage of the trans-Caucasus energy corridor now being developed through Azerbaijan and Georgia.

All these developments, of course, are taking place against a background of low oil prices. The result is that projects are more likely to be successful if they grow incrementally. This is perhaps the most telling point in favour of a Baku-Supsa route for Azerbaijan's MEP, as opposed to a line between Baku and the Turkish Mediterranean port of Ceyhan. A Baku-Ceyhan line has immense long-term advantages. It could be made to serve not only Azerbaijani but Kazakhstani interests; it removes any controversy over increased shipping in the Bosphorus; and this obviates the need for costly 'Bosphorus Bypass' oil pipelines, such as those proposed between Burgas in Bulgaria and Alexandroupolis in northern Greece, or between the Turkish ports of Kiyikoy and Ibrikbana, following a line a little way north of the Sea of Marmara.

In the meantime, AIOC has been given a reprieve concerning its most difficult task: its actual recommendation for an MEP route. In theory, it is to choose between three routes: Baku-Ceyhan, Baku-Supsa and Baku-Novorossiysk – but in practice the latter is ruled out because of the uncertainties and delays in any pipeline route transitting Russia and the uncertain situation in Chechnya. Baku-Ceyhan has massive political backing, with the US Special Envoy to the region, Ambassador Richard Morningstar, saying it is not a matter of if, but when, the Baku-Ceyhan line will be built.

The companies beg to differ, arguing that Baku-Supsa makes much better commercial sense and saying that if they are to agree to a Ceyhan line on essentially political grounds, then who will pick up the considerable extra costs involved? At present, a full-scale MEP to Supsa is costed at $1.8bn, whereas AIOC's member companies cost a comparable line to Ceyhan at up to $3.8bn. Turkish government assertions that the line could be built for much less – for around $2.2 bn – are attributed to differences in both route and specifications. In effect, since both would follow the same right of way established for the existing Baku-Supsa early oil line for their first 600 km, the choice is effectively between a 300-km line from the inland Georgian city of Gori to Supsa, or for a 1,400-km line from Gori to Ceyhan.

Shipment costs

The problem is further complicated by likely tariff charges. Shipment costs to Supsa are likely to be around $2/b, whereas costs to Ceyhan would be roughly double that sum. With oil production costs of around $5/b – and prices still hovering at around the $10/b mark in early 1999 – there is virtually no room for give and take.

AIOC, which was originally committed to making a firm recommendation on the favoured route for a MEP by October 1998, has now said that it does not expect to deliver such a recommendation until mid-1999. Both AIOC and the Azerbaijani authorities will be hoping that prices have recovered by then so that, whichever route is recommended, there will be reasonable prospects for at least modest profits as the early oil Baku-Supsa line comes fully into service.

Regional gas exports

For Turkmenistan, the absolute priority has to be to secure a reliable gas export delivery system. In 1998, closure of the Russian pipeline system to Turkmen exports to other FSU states prompted production to fall to just 13.2bn cm, little more than one-seventh of the country's peak production of 89.9bn cm achieved in 1989. The Turkmen authorities have two potential outlets for their gas this year, but remain optimistic that a third outlet, across the Caspian and through Azerbaijan and Georgia to Turkey, can somehow be built to allow them to start exporting substantial volumes of gas to hard cash markets in the west during the year 2000.

Throughout 1998, the country had only one export system in operation, the newly built 200-km line from the Korpedzhe gas field, near the Caspian, to Kurt-Kui in northern Iran, where it connects to Iran's own east-west pipeline which carries gas from its north-eastern fields near Serakhs to the Caspian port of Rasht. This line is a modest affair, built by Iranian companies for $195mn and, at its opening in December 1997, said to possess an initial capacity of just 3bn cm/y. A compressor station was scheduled for installation in 1998, to take capacity up to 4bn cm/y, whilst the original agreement calls for the line's eventual capacity to reach 10–12bn cm/y.

The first actual deliveries of Turkmen gas are understood only to have arrived in Iran in mid-1998, and, so far, only small volumes are reported to have been dispatched through the new line. However, the existence of this line does at least open up the possibility of initial sales into the northern Iranian market or possible swaps, and eventual direct deliveries, to Turkey via the Iranian gas line network.

At the end of December 1998, Turkmenistan announced that it had finally concluded an agreement with Russia's Gazprom under which it will be able to resume gas exports to the

The main oil pipeline projects

1 *CPC pipeline: Atyrau–Novorossiysk* Studies and international agreements in place – construction of missing links yet to start.

2 *Baku–Novorossiysk* In use by AIOC. Russian portion controlled by Transneft.

3 *Baku–Supsa* Rebuilding of 'early oil' line virtually complete; one of two main proposals for Azerbaijan.

4 *Baku–Ceyhan* Under study by AIOC, the Turkish and US governments; the second main proposal for Azerbaijan.

5 *Baku–Iran* a proposed option probably via Tabriz, under consideration by France's TOTAL.

6 *Tengiz/Uzen–Kharg* Proposed route being promoted by TOTAL.

7 *Chardzhou–Ras Malan* Proposed to export Turkmen and Kazakh production via Afghanistan promoted by Unocal/Delta. Now effectively abandoned.

8 *Trans-Caspian* Various proposals involving Amoco, Texaco and Turkish government.

9/10 *Tengiz/Uzen–Kharg* New lines needed to link production to Kharg, promoted by Iran, TOTAL.

11 *Uzen/Tengiz – China* Under study and being promoted by China National Petroleum Corp.

12 *Atyrau–Samara–Druzhba system* – In existence. KazakhOil is promoting expansion capacity.

Ukraine after a 21-month hiatus. However, Turkmenistan will pay a high price for this privilege. The price of Turkmen gas at the Turkmenistan border with Uzbekistan has been set at just $36 per 1,000 cm, in contrast to a price of between $68 and $72 when it crosses the Russian-Ukrainian border. In addition, Ukraine is to pay only 40% in hard cash, with the rest covered by delivery of goods and services.

Thus Turkmenistan has every incentive to try to secure agreement on alternative export routes, and the one which currently seems most likely to make progress starts with a subsea line across the Caspian to Azerbaijan, and then follows the Kura valley into Georgia before heading south-east to connect to Turkey's new pipeline system at Erzerum. In October 1998, Turkey signed an agreement to import 16bn cm/y of Turkmen gas, implicitly by means of this line. But although US company Enron has presented the Turkmen government with a preliminary feasibility study (paid for by the US government) for such a line, the trans-Caspian gas line still remains a proposal rather than a project. No financing package has yet been prepared (although President Niyazov has said the World Bank will help finance it) and no procurement arrangements made (Enron said the line would take two to three years to construct).

What is worth noting, however, is that Turkey has started to build the necessary infrastructure within Turkey to serve such a line. In 1997, the then Islamist-led Turkish government ordered a start to pipeline construction between Erzerum and the Iranian border to carry gas ordered under a 1996 agreement with Iran. The Iranians began building a connector to the border from their north-western city of Tabriz and these sections should both be completed this year, enabling Iran to deliver, initially, some 2.0bn to 3.0bn cm/y of gas to eastern Turkey. But the real prize is deliveries to central Turkey, especially the capital of Ankara. On 9 November, Turkey's last Prime Minister, Mesut Yilmaz, formally broke ground as implementation of four major pipelaying contracts finally got under way to link Erzerum with the central Turkish city of Kayseri and to link Kayseri by one line to Ankara and by another to the southern city of Konya.

Iranian gas

These lines could, of course, equally well serve to distribute Iranian gas throughout the Turkish market, but there is little doubt that it is Turkmen gas which the Turks wish to secure. Moreover, whilst Turkey will certainly be happy to receive some Turkmen gas initially via the Korpedzhe to Kurt-kui pipeline, its real goal – which is as much political as economic – is to receive it via the Caucasus. Moreover, although Turkmenistan had commissioned Shell to look into its own long-favoured project of an overland gas line to carry its gas across Iran to Turkey, Shell came to the conclusion in December that there was simply not enough scope at this stage for two major export pipeline projects from Turkmenistan, and that the trans-Caspian route currently looked the most hopeful.

With the US government equally determined to develop a trans-Caspian gas line through Azerbaijan and Georgia to Turkey, the chances are that 1999 will see some significant progress on this front. It is just possible it might even be brought to fruition as part of a package which would see a MEP routed, at least initially, to Supsa, whilst leaving open the possibility of a subsequent spur or extension to Ceyhan to a later date when it could share the same rights of way as the trans-Caspian /trans-Caucasus gas line for much of the route.

Forward thinking

Only ten years ago you could walk into many oil company trading rooms and find that the only concept of hedging being practised was purely physical. Even the futures markets were still in their infancy, and few people had either cause or opportunity to consider what use derivatives might be. Today the reverse is true with the petroleum industry having developed a wide range of financial trading instruments. The most significant changes have been in the over-the-counter (OTC) market in forward contracts. *Mary Jackson*, Global Service Manager for Saladin, reviews an evolving trading picture and outlines what needs to be done to enable OTC markets to reach even greater heights of popularity and sophistication.

The oil industry always has been and always will be firmly grounded in the physical markets, but probably four to five times the delivered commodity is now traded worldwide. With the growth curve for derivatives trading now turning progressively upwards, it is curious to recall how sluggishly this era began. Indeed, the profile might still be a very gentle one had it not been for a dynamic interplay with the financial trading markets that continues today.

The futures markets, particularly the IPE and NYMEX, have now become thoroughly embedded in the industry and in the world's economies. In the late 1980s, however, neither producers nor consumers had enough experience to embrace futures trading enthusiastically. The financial traders on the other hand were looking for opportunities to manage interest rate risks in the boom economy and to expand. The new exchanges provided a convenient hook for establishing energy trading rooms. These traders brought fresh expertise into oil trading and, as they began to look outside the organised exchanges to forward contracts, they introduced counterparties in oil companies to new opportunities.

Risk management

A second factor contributing to use of OTC derivatives was the rapid growth of risk management. The startling consequences of crises such as those at Barings and Metalgesellschaft brought risk practices and policies sharply into focus. The changes subsequently adopted in oil companies worldwide have led to a greater understanding of how best to use and control derivatives trading at all levels in the organisation. As a result, more people are now more comfortable with OTC trades.

OTC attractions

Like futures contracts, OTC contracts can be used for either hedging or speculating on future price movement. But the OTC markets have some strong and distinct attractions for oil traders – foremost being their flexibility. OTC contracts come in various guises, from straightforward swaps and options to more exotic variants such as swaptions, collars, and caps.

Because they are bilateral contracts, they can be tailored to meet the specific needs of the two counterparties in terms of the quantity and quality of the commodity, payment terms, pricing markers, and timing. Traders no longer need to view every product against gasoil and every crude against Brent.

In addition, because these are purely financial transactions, risks associated with delivery are avoided. Furthermore, they are less costly to execute than futures and exchange-traded options as the margin payment required by the exchanges does not apply.

Further development

Having now reached the point where forward markets are bread and butter for most traders, however, a major issue has emerged that is influencing further development – the lack of good information. A combination of widespread use of OTC contracts in trading and greater attention by management to validating how books are marked to market has revealed deficiencies in:

- how pricing information is sourced;
- how trustworthy it is;
- how it can be stored in a useful, meaningful format; and
- how access to it can be managed and controlled.

In addition, proposed EU legislation to regulate financial markets is creating a focus and sense of urgency for change.

Challenges and solutions

Unlike the futures exchanges where transactions are transparent to the whole market, OTC deals are private. With no public mechanism for tracking trades, data is currently available primarily in the form of quotes issued by brokers, with a few providers such as Petroleum Argus, Reuters and Telerate publishing assessments. Problems arise because each broker is covering a particular set of niche markets and regions, and only a subset of the clients for that market. Not all information from all brokers is available to all traders so gaps can easily arise, and if no deals are done for a few days – in illiquid markets such as naphtha, for instance – no quotes are issued.

The prime issues here are dependability and reliability of information. If a specialist team departs en masse, as recently happened in London, can you still depend on the broker's quotes? If there are only a couple of trades a week, how reliable is the forward curve? If the market is very fragmented – like that for unleaded gasoline where multiple grades and regions exist – how relevant is the small subset of quotes from a single broker? And, at the end of the day, if the brokers' prime business is broking, how much focus can they realistically be expected to place on gathering, validating, distributing and supporting price information?

The consensus emerging in the industry is that one solution for these issues lies in greater transparency. But who will lead the initiative, and how? Some rationalisation has occurred progressively – meaningful North European jet quotes have been available for some time, for example, and a well understood shorthand exists for the main commodities – but this may be a pre-

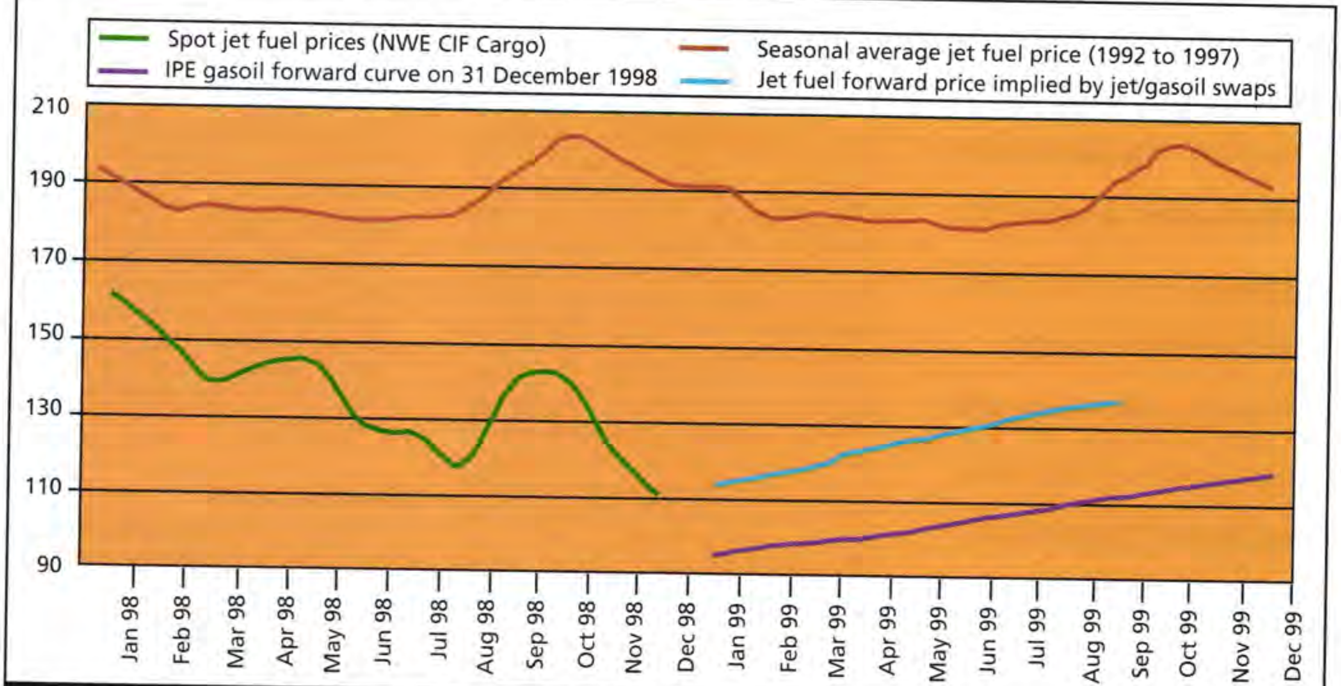


Figure 1: European jet fuel forward curve
The jet fuel swaps market is one of the longest established and most actively traded OTC markets in Europe. Most trading is in basis swaps between spot jet prices and the IPE gasoil futures. At the end of 1998, a time of historically low distillate prices, the jet forward curve showed prices rising steeply with time, reflecting both strong contango in the futures market and a widening basis spread.

cursor to wider market revision.

According to Paul Newman, Managing Director of Intercapital Commodity Swaps, the leading OTC derivatives brokers: 'The next step may be an index like FEOP in Asia-Pacific, or a LIBOR-style listing, that could give a more relevant pricing reference. However with players getting in and out of the market, it's difficult to see how this could work reliably.' Other problems inherent in the business, such as the competitive nature of the information, mean that the full solution will take time to devise.

Information management

As the prime consolidator of energy information, Saladin's approach in the meantime is to ensure that it knows what information is available in what markets and to make more of it accessible to clients: more brokers, more markets, more coverage will be available this year. It has also been in the forefront of developing a solution to the second information dilemma: what to do with it once you have it. Many traders still only keep forward curves in their books, or at best in spreadsheets. Often trading organisations have little control over how forward curves are set up or the reliability of the underlying data, they provide no mechanism to share or standardise, and they run the risk that not everyone who uses them knows what they mean. Today's risk-conscious management must understand how books are marked to market. The solution lies in information management, an ever more urgent priority as the volume and use of information rises inexorably.

To meet this critical need, Saladin introduced its EnergyServer information warehouse platform and developed a specialised add-on feature, Curve Manager, in conjunction with market leaders. By providing a tool to store appropriate data in a suitable format, to analyse the OTC markets over time, and control access to and use of forward curves, the company can give traders themselves the ability to make sense of a non-transparent, patchy market.

The ability to capture and share forward market information centrally also ensures that the whole organisation can use consistent prices for everything from trading decisions through to risk assessment and accounting. Initially devised to handle the relatively simple structures of monthly, quarterly and annual swaps, Curve Manager is being expanded to cope with trading based on pipeline cycles and complex market structures such as the Brent contracts for difference (CFD) market.

Forwards for the future

The use of forward contracts is accepted industry-wide, popular and easy to understand – only global majors like Exxon with massively integrated worldwide businesses can afford not to be using them. Growth is looking especially strong among end users: airlines, shippers and, particularly, utilities who have imported trading talent widely from banks, trading houses and energy companies. The issue now is not whether, but how, to deal with OTC markets.

The industry is demanding more and more transparent information. The catalyst this time may be regulatory legislation or it could be an initiative led by the more forward thinking brokers.

Even in advance of more standardised, transparent quotes, every player in the industry needs to be able to deal efficiently and effectively with the information that is already available. Financial traders coming into the energy markets have brought not only the use of innovative instruments, but key skills, sophistication and expertise. Exploiting this in conjunction with the knowledge of markets embedded in trading organisations can bring significant competitive advantage. Tools like Curve Manager and processes for information/knowledge management are the way forward. Such ideas are already being enthusiastically embraced by market leaders such as Koch, Elf and Shell and much more widely.

As has been seen in the financial world, OTC trading is set to grow fast in sophistication and usage. Virtually every trading organisation, even (or especially) the smaller players, can benefit, but how much will depend on how well they can manage the crucial information.

Erratic reserve reporting

Assessing the size of the world's oil reserves is a subject of much debate and contention. *Jean Laherrère*, consultant and industry writer who was Manager of Exploration Technique for TOTAL until his retirement, assesses some recent developments in this area and calls for the industry to put its house in order by developing and using consistent reserve definitions.

In August 1998, the magazine *World Oil* made a dramatic 11% reduction in its annual estimate of world reserves for the end of 1996 removing 183bn barrels from its previous estimate of 1,160bn barrels. Likewise, the US Geological Survey (USGC) has reduced its estimate of the total discovered from the 1,802bn barrels reported in 1994, to 1,608bn barrels (report 97–463). By contrast, Petroconsultants has increased its estimate of proved and probable reserves from 945bn barrels to 990bn barrels in its latest *World Petroleum Trends (WPT)* report, mainly by accessing new Former Soviet Union (FSU) data, some of which is of questionable validity.

Explanation

World Oil (WO) offers the following explanation for its revision: 'During the past 12 years it was fashionable and politically expedient for some nations to periodically boost reserve figures beyond increases that E&P would deem appropriate. Often, these new reserve figures seem to have gone beyond the traditional definition of "proved" to include "probable" and even "potential" deposits.'

A number of factors are at work which have combined to produce the current inconsistencies:

- There is no standard definition and conflict between the determinist and probabilist camps rages on.
- Companies quoted on the US stockmarket are obliged to follow the Securities and Exchange Commission's (SEC) restrictive rules. These limit reserves that can be described as 'proved' to reserves in the catchment area of existing, producing wells. In contrast companies quoted on the UK stockmarket can report both 'proved' and 'probable'.
- The World Petroleum Congress/ Society of Petroleum Engineers (WPC/SPE) rules are ambiguous and contradictory, and are generally not followed in practice by the companies which commonly carry different estimates for internal and external purposes.
- It is statistically inaccurate to sum the 'proved' reserves of a country: only mean (expected) values can be totalled.
- It is misleading to quote world reserves to the accuracy of one thousand barrels, given the 14% range in the publicly published estimates for 1996 – 1,160,104bn barrels for *WO* and 1,018,849bn barrels for *Oil and Gas Journal (O&GJ)*. Following *WO*'s downward revision the difference in 1997 reserves was rather smaller at 4.4% (974,179bn barrels for *WO* and 1,019,546bn barrels for *O&GJ*).

US experience

The US experience over the past 20 years is that positive revisions exceeded negative revisions by a factor of two. This is a very telling statistic because it means that the so-called 'proved reserves' effectively have a 65% probability. This implies that the reserves are not in fact 'proved' as they are supposed to have a 90% probability as now defined by SPE/WPC. It also explains why the sum of US reported reserves in practice add up to something closer to the mean value, and are not therefore too bad.

North Sea experience

The North Sea countries, most companies and Petroconsultants report 'proved + probable' reserves, in accordance with UK accounting procedures. Studies by BP, Statoil and the UK DTI show that, in the North Sea, there are as many negative as positive revisions, meaning that the probability is close to 50% or to the mean.

However there is a global trend to a small increase. Small fields with a high economic threshold need high reserve estimates to proceed and are often overestimated, whereas large fields are often underestimated. The important point is the dating of the revisions. Petroconsultants correctly backdates revisions to the discovery of the respective fields, whereas *WO* and the *O&GJ* take them on a current basis.

Petroconsultants reports world data in *WPT 1998*, which is compiled from its 18,000-field database (Iris 21) and a separate North American database.

The UK Offshore Operators Association (UKOOA) reports that the total discovered, as of end 1994, was 27.5bn barrels for the UK Continental Shelf (UKCS). Subtracting the 12.9bn barrels of cumulative production to that date gives reserves of 15bn barrels. However the UK government actually reports so-called 'proved' reserves at

5bn barrels, a figure which is reproduced by the *O&GJ* and BP in its *Statistical Review*.

From 1974 to 1986 *O&GJ* reported UK reserves as twice as much as *WO* reported. For 1993, *WO* reported three times more than *O&GJ*; but now they both report around 5bn barrels. Petroconsultants reports around 15bn barrels for UK reserves based on a logical plot showing the progressive decline in reserves as the large fields, which were found early, are depleted.

Norway also shows erratic reporting, despite official releases. Up to 1989 both *O&GJ* and *WO* reported the same values, but when *O&GJ* values stayed little changed, *WO* raised the reserves up to 25bn barrels for 1995 and then back to around 10bn barrels (11.7bn barrels for 1997), to match *O&GJ*. The Norwegian authorities report 10.9bn barrels for developed fields, as of end 1997, and 15.9bn barrels for total discovery, as is also reported by Petroconsultants. The distortion due to the failure to backdate is very evident.

FSU experience

This is a particularly difficult area because no technical or economic constraints were taken into account with the reserve definitions used under the Soviet regime. For example the largest Russian field, Samotlor, is reported to have reserves of 10bn barrels with a 50% recovery factor, yet it is now declining at 15%/y with a 92% watercut, having recovered only 30% of the estimated oil-in-place.

The reported 10bn barrels is not likely to be achieved. Halliburton Energy Services plans to rehabilitate the field and to produce around 370,000 b/d over 20 years, which will give a cumulative production of less than 3bn barrels, so total recovery will be far less than the reported 10bn barrels.

From 1991 to 1995, *WO* reported FSU reserves of around 180bn barrels whereas *O&GJ* reported around 60bn barrels. Now *WO* is back to 60bn barrels. Petroconsultants' estimate of 170bn barrels appears far too high.

Decline curve analysis of 85 Russian fields, making up one-third of the total reported discovery, gives reserves of less than half those reported in 1997 by Petroconsultants.

FSU production peaked before 1990 after 100bn barrels had been produced, almost certainly close to the midpoint of depletion. Some 20bn barrels have been produced since, with about 80bn barrels left as indicated by decline analysis.

Figure 1 shows the correlation between discovery and production peaks with a 15-year time lag, which gives a close fit, notwithstanding the impact of the post-communist operating difficulties. The evidence suggests that total liquid discovery is about 200bn barrels as of the end of 1997, of which 128bn barrels have been produced.

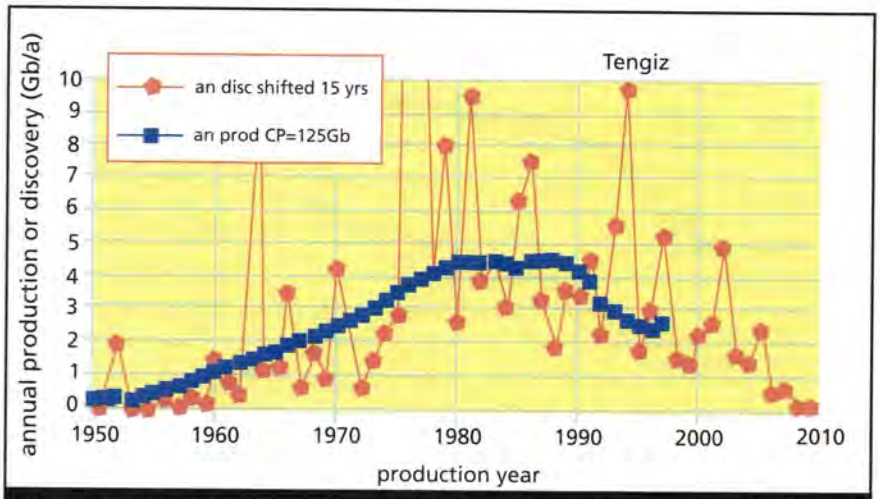


Figure 1: FSU: correlation between annual production and annual discovery shifted by 15 years

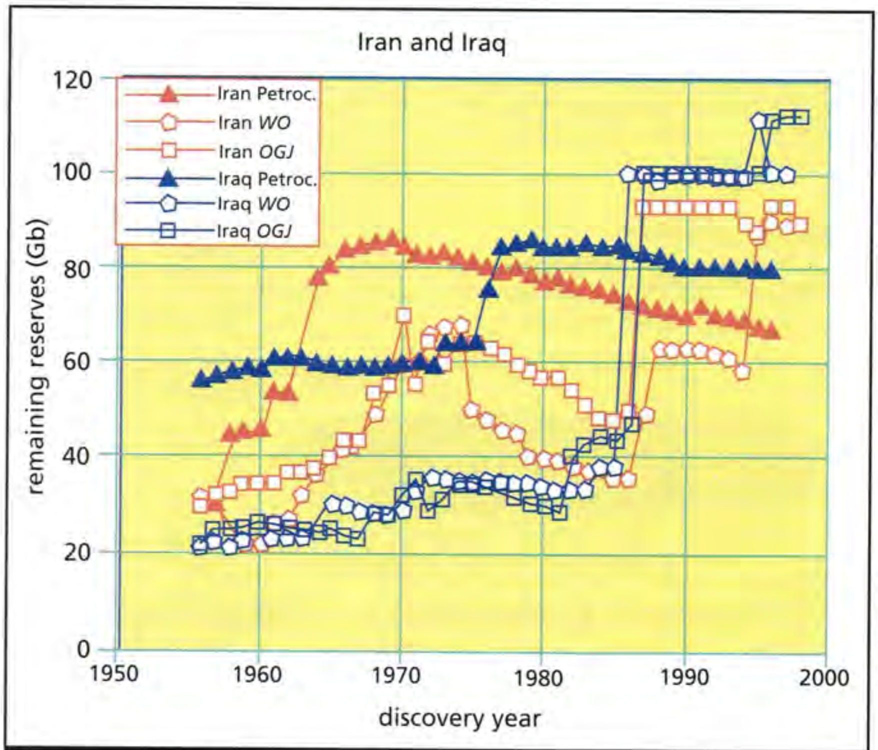


Figure 2: Comparison of reserve estimates for Iran and Iraq

Middle East experience

It is now widely accepted that the huge increases, announced in the late 1980s by several Opec countries were motivated by quota considerations as quotas were partly defined by reserves. The fact that the reported reserves have in most cases barely changed since is equally implausible. It is also significant that the Neutral Zone announced no increase in the late 1980s. It is owned jointly by Kuwait and Saudi Arabia who had no common motive in relation to reporting its reserves.

Both *WO* and the *O&GJ* have reported the same reserves for Kuwait and Iraq since 1980, but Petroconsultants carries much lower numbers. In the case of Iran, there was a greater discrepancy, as shown in **Figure 2**.

Mexico and Venezuela

The numbers reported by *WO* and *O&GJ* have been similar save for the last two years when the estimates diverged. Petroconsultants again carries lower numbers. The reason in part is that

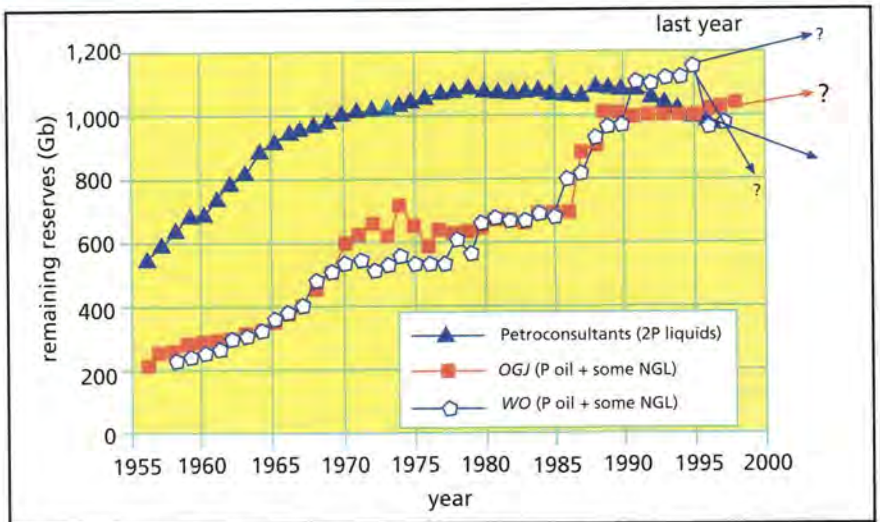


Figure 2: World Oil, Oil & Gas Journal current reserves (P) and Petroconsultants backdated values (2P)

both Venezuela and Mexico include large amounts of non-conventional oil in their data, without there being any clear demarcation.

World experience

Figure 3 shows the world position. Petroconsultants (*WPT* for the last ten years) show a logical smooth curve (except for the break between *WPT* and its predecessor, the *WPRS Report*) showing that the decline of reserves has set in. From 1955 to 1990, *WO* and *O&GJ* report a similar rising trend being much influenced by the increases of the late 1980s which should have been backdated. *WO*'s major recent downward revision after a five-year period when they were well above other estimates, gives rise to a misleadingly steep declining trend.

In conclusion, it can be said that published reserve data are unreliable. The reporting of reserves is very much a political act whether by governments for quota reasons or by companies desiring to deliver a promising message to the stockmarket. The inappropriate rules of the SEC and the failure of the industry to agree firm procedures make this possible. Reserve estimates are estimates and, as such, are subject to uncertainty which is to be measured in terms of statistical probability.

To sum the so-called proved reserves of individual fields to obtain a country total is a flawed statistical procedure. The only valid method is to sum the mean value. This is rarely reported as such but in practice comes close to P50 reserves or proved + probable reserves.

Many analysts blithely accept these reported numbers as a basis for a wide range of important studies and pronouncements without checking the validity of the underlying input. It is high time the industry put its house in order.

Petroconsultants is thanked for permission to use its confidential database

Upstream asset opportunities – but cash is king

Given the low oil price environment, 1999 is likely to prove to be a year of significant opportunity in the global upstream asset market for those companies with both the financial strength and/or corporate vision to identify and effect transactions that meet their strategic criteria.

This article summarises key issues from the asset market and sets out our views. We welcome your responses and opinions. If you would like to understand more about the ideas raised in this article and how Wood Mackenzie's consultancy services might assist you please call any of the contacts listed on the last page of this article.

1998 was a momentous year for the industry in many ways, with corporate merger activity and rationalisation grabbing the media headlines. 1999 will see further corporate rationalisation but we anticipate that the asset market will re-emerge from the shadows as an important strategic arena for companies, gathering momentum and creating a significant number and range of opportunities in the market.

Executive Summary

The asset market in 1999 will present an opportunity for all companies to expand, rationalise or refocus their portfolios. Companies who are sellers must 'high-grade' their asset portfolio in a way that fits with their geographical concentration and strategic vision. Companies who are buyers must consider taking advantage of the asset market now. Buyers who take a proactive approach will maximise their chances of success.

Some of the main themes that are likely to emerge during 1999 are:

- Cash will be king in 1999. Equity markets remain closed for new capital raising, at least for now – the spate of mergers delivering paper, rather than cash, in enlarged entities into the hands of an investment community seemingly keen to reduce its exposure to the sector. Evidence shows that, as cash flow levels have dwindled over the past 18 months, the financial strength of companies has been sapped, thereby limiting the scope for further increases in debt levels.
- As companies focus increasingly scarce capital on "core areas", active portfolio management including wholesale exit from particular regions/countries will be undertaken to re-direct resources and maintain corporate momentum.
- At the same time, we are aware of a small number of competitors in the market with the desire and cash to effect sizeable asset acquisitions in 1999. However, if oil price and equity market conditions prevail, the overall scarcity of cash within the market is likely to act as a brake on the number of such transactions early in the year. As asset disposals are made and fresh capital is injected into the market, this position should gradually unwind itself with further momentum being generated for cash asset deals. Nevertheless, with financial pressures as they are, the volume of deals is likely to be boosted by deals being effected through both swaps and farm-out mechanisms.

Within an 18-month period since the end of 1997, we are likely to have moved from a strong sellers' to a strong buyers' asset market. Companies looking to effect disposals for cash will need to target buyers; timing will be crucial and tactics may be complex.

Given the macro economic conditions and the number of opportunities on the market, it will be much harder to sell lower quality assets in 1999 than in recent years.

Companies looking to buy assets are not likely to be opportunity constrained; the challenge will be to remain focused and target opportunities that fit within a clearly defined strategy. Rigorous asset screening and a proactive approach to the identification of potential vendors will be essential to secure the best results. There are also significant opportunities for asset swaps and farm-in opportunities as part of the strategy for 1999.

The Upstream Asset Market Cycle

Some key messages can be drawn from asset market conditions over the past two years providing evidence of a change from a sellers' market to a buyers' market.

1996/7 – Strong Sellers Market

Buoyant oil prices in 1996 and 1997 fuelled a wave of optimism within the industry and saw a period of significant capital spend and strong cash flow. During this period companies continued to invest in the development of assets on their books as well as searching for new opportunities. At the same time there was a limited number of high quality asset opportunities coming onto the market, resulting in intense competition for the few put up for sale and significant premia being paid to estimated Net Asset Value to secure such opportunities.

For example the 1996 sale of Kuwait Petroleum's (Santa Fe) UK and Ireland business attracted interest, particularly as an entry vehicle, and resulted in an intense auction process ultimately won by Saga for $1.23 billion. Saga has subsequently taken two write-downs and made a disposal from the package. Opportunities in countries previously closed to western oil companies also provided scope to acquire substantial reserves in the ground, to which best practice skills and technology could be applied. An often cited example is LASMO's $453 million purchase of the Dación block in Venezuela.

1998 – A Transitional Year

1998 represented, in our opinion, the transition period between the sellers' market of 1996/7 and the buyers' market of today. Whilst the number of deals declined from the peaks reached in 1997, the volume of reserves transacted increased and prices paid for those transactions completed seemed to hold up very well for at least the first half of the year. Intrepid's purchase of certain UK assets from Enterprise for $264 million perhaps being one of the last of the large "premium" transactions to take place before the lull in summer 1998. A number of companies had remained, until then, optimistic that the fall in the oil price would be matched by an equally quick price recovery during 1998. Others warily viewed the prospect of reduced oil prices and, as pessimism over prospects for recovery increased by mid-year, demand levels began to fall.

It was in the second half of 1998 that buyers started to retreat from the market place as the full impact of sustained low prices was digested, resulting in a lull in asset activity. Deal volume and prices paid fell at the same time as corpo-

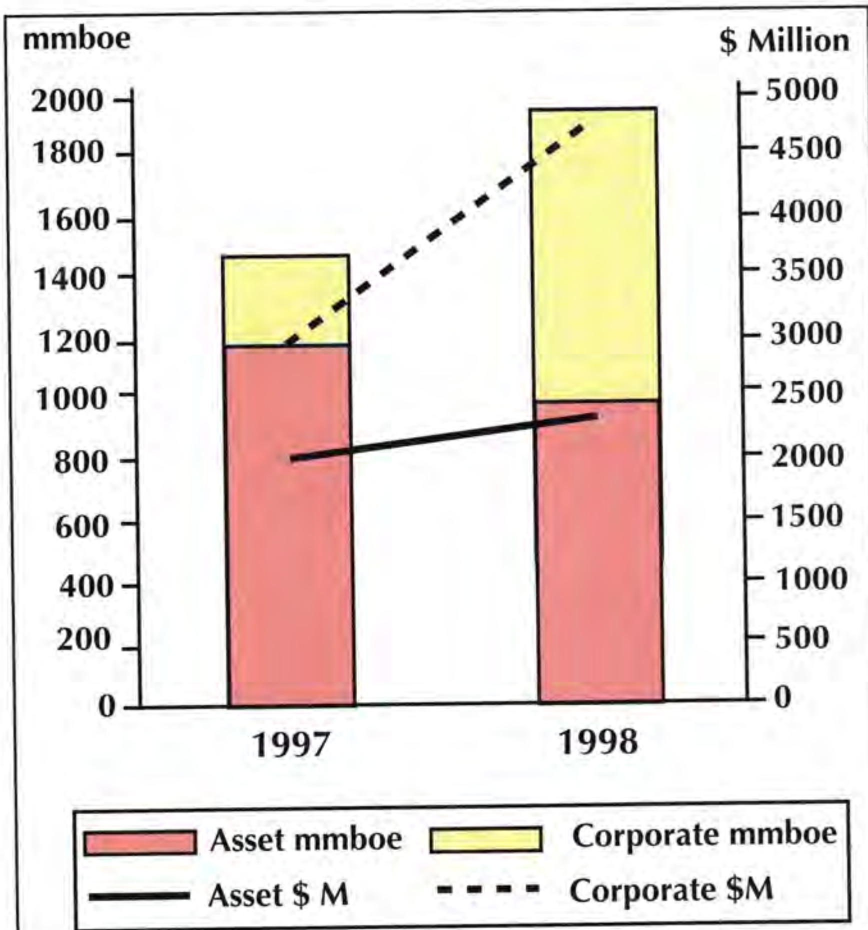


Figure 1: UK Asset Deal Activity 1998 vs 1997

rate mergers began in earnest with the announcement of the BP Amoco deal in August. During this period, assets started to fail to find a home and a number of plans for disposals were shelved and some asset packages (such as Repsol's attempted exit from Indonesia, Sibir's UK portfolio disposal, Shell's upstream business in Thailand and Kingfisher field in the UK) were withdrawn from the market.

In the UK, signals from the asset market were mixed. Whilst overall activity in value and reserves traded increased, this was a function of increased corporate deals including BP/Amoco and Kerr McGee/Oryx. As far as asset transactions were concerned, the number of deals completed and reserves traded fell in 1998 compared with 1997, despite the average value increasing marginally – indicating that fewer, but larger, packages were traded.

In North West Europe as a whole, asset transactions (in number of deals, reserve volume and value) fell in 1998 compared with 1997 as the level of uncertainty and the distraction of corporate restructuring took hold. In South East Asia, there was increased asset activity as companies sought to rationalise regional portfolios in response to both global cost pressures and, importantly, the effects of the Asian economic downturn. In less liquid markets, such as Africa and Latin America, the general trends of exploration farm-ins continued although signs of increased levels of consolidation and exit emerged during the latter half of 1998.

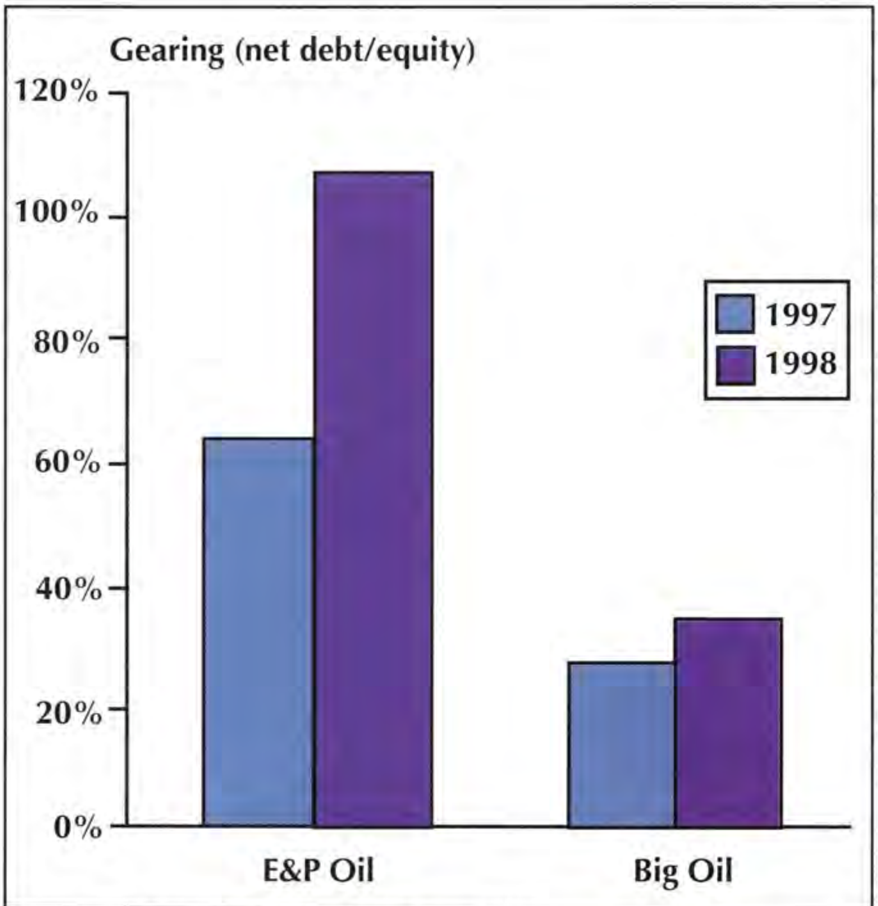


Figure 2: Oil Company Gearing end 1998 vs end 1997
'E&P Oil' and 'Big Oil' are a representative cross-section of 10–15 international companies

A key factor impacting trends within the asset market in 1998 was the effect the oil price had on gearing levels of the oil and gas players. As **Figure 2** illustrates, whilst this was particularly true within the E&P oil sector, "Big Oil" or the majors were also affected (albeit to a lesser extent). With oil prices remaining low, this situation can only worsen.

Likely trends in the 1999 asset market

Having outlined how some of the key asset market drivers have changed, the purpose of this article is to draw-out how we see these elements influencing activity during 1999. Two factors in particular will differentiate asset market trends in 1999 from those in 1998:

- new (reduced) annual budgets are now in place, placing cash constraints on E&P businesses and requiring the careful allocation of scarce resources to maintain growth and development of businesses;
- many sellers have revised their asset price expectations downwards and most companies have taken (or will take) the opportunity to write-down book values of assets, allowing a greater level of much needed disposals to start taking place without book losses being recorded for transactions.

We anticipate the following trends:

- **active portfolio management** including disposals of non-core assets as part of post-merger/downsizing rationalisation processes and/or to free-up capital for re-investment in remaining activities.
- **wholesale exit from areas/ countries** in order to realise capital, reduce commitments and overheads and allowing focus to be placed on "core areas".

- **farm-outs** offering companies an option to retain an interest in key assets whilst reducing capital commitments.

So far, we have determined that 1999 will see more sellers of assets. However, it is clear to us that there will be insufficient numbers of cash buyers in the market to match the expected number of opportunities, increasing the likelihood of asset swaps and deferred consideration/farm-outs as means to effect asset transactions.

Certain companies whose business mix has ensured less exposure to the low oil price environment have been increasingly active in acquiring upstream assets or growing existing upstream businesses: Eastern in the UK, TransCanada Pipelines in the Netherlands, and Gaz de France through deals in the UK sector of the North Sea with French majors Elf and TOTAL, and an attempted acquisition from Saga in the Norwegian sector. These companies have the funds to take advantage of the depressed upstream asset market in order to develop increasingly integrated energy businesses (the gas value chain in particular). They will also inject new capital into the upstream asset market.

What should companies be doing now?

As sellers companies should:

- 'high-grade' their existing asset portfolio to focus on core activities: identify core assets that offer greatest value (real or potential) and identify disposal candidates. This may involve the selective withdrawal from certain countries/regions, as well as portfolio rationalisation within identified core areas – for example to focus on assets/areas which offer lower risk production/reserve upside potential, where the company has or could achieve stronger equity positions or where other opportunities are likely to become available to further enhance identified priority areas;
- look to sell all non-core assets, but aim wherever possible to offer indivisible packages for sale that mix both attractive assets (ie in production or under development) as well as the less desirable ones;
- target buyers and consider the most appropriate sale route for the asset package(s) involved. In the majority of cases this might involve a competitive auction or exclusive private negotiation;
- where cash buyers are not available or desirable, vendors may consider:

  – looking to initiate discussions with likely swappers of assets. This will require analysis and preparation to ensure a targeted and effective approach;

  – proposing a farm-out structure as part of its selling process and negotiations.

As buyers companies should:

- if cash resources are available, consider taking advantage of the buyers' market now;
- take a proactive approach in the identification of assets of interest and analysis of the motives of the owners. This requires the determination of a focused strategy to identify core areas for development as well as an understanding of the issues of relevance to the potential vendors;
- remain alert to opportunities coming on to the market and be ready to respond as appropriate. Overall, given the likely number of opportunities available, we would recommend that companies remain focused on developing their chosen areas and should not be tempted into pursuing opportunities that do not fit within their chosen strategies;
- seek exclusivity in negotiations wherever possible. A proactive approach targeting vendors may help to achieve this.

How Wood Mackenzie can help

With 25 years' experience analysing, and providing advice to, the energy sector, Wood Mackenzie is uniquely placed to assist companies considering developing their portfolios through selling and/or buying assets.

Wood Mackenzie applies its comprehensive knowledge of the market to support companies in the development and implementation of their corporate strategies. We are uniquely positioned to identify opportunities for buyers through detailed screening and knowledge of companies in Europe, Africa, Asia, FSU, Latin America and the Gulf of Mexico.

Should the client desire, together with Bankers Trust through the energy sector advisory team led by Rob Gray, we can offer a seamless service from analysis to successful deal completion, combining the consulting skills of Wood Mackenzie and the advisory and execution capabilities of Bankers Trust.

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More nuclear plants to meet Kyoto targets

Japan's Electricity Utility Industry Council (JEUIC), under the Ministry for International Trade and Industry (MITI), recently published a report outlining revised long-term development plans and forecasts for the nation's electricity industry, as part of a wider government review of Japan's overall long-term energy supply and demand outlook until 2010, reports *David Hayes*.

Fukushima No1 Nuclear Station, Tokyo Electric (TEPCO), Japan. All photos in this article by David Hayes

The JEUIC was asked to carry out the power sector development review after the government signed a protocol agreement to reduce Japan's carbon dioxide (CO_2) emissions by 6% by 2010 at the Kyoto Conference in December 1997.

To achieve the CO_2 emission reduction target the government has proposed a major increase in nuclear power generation while reducing the use of oil as power plant fuel. Coal and imported LNG will remain major power station fuels in future while efforts continue to develop Japan's limited hydroelectric power resources.

Implementing the new long-term power development programme poses a major challenge. Ensuring government targets are met is one of the key issues being considered as part of plans for further partial deregulation of Japan's electricity industry, now under study by the JEUIC's Basic Policy Committee which was due to report its findings at the end of 1998.

'The electricity industry is already highly efficient so to reduce CO_2 emissions is quite hard,' commented a spokesperson for Japan's Federation of Electric Power Companies (FEPC), 'Japan will do it by developing nuclear power which is the only feasible solution. Japan has to reduce CO_2 and still increase power output. LNG-fired generation will increase too because of low CO_2 emission. Japan can set high nuclear targets but they still have to be achieved.'

Although nuclear power development is the government and power industry's preferred method of supplying the country's growing electricity needs, public opinion is not so supportive of rapid nuclear power growth. Nuclear station construction schemes regularly run into planning problems due to public protests, causing electricity utilities major problems in finding remote greenfield sites where nuclear stations can be built.

Japan's major energy source

Nuclear power is already Japan's major source of electricity. In the financial year ending 31 March 1997 nuclear power generation reached 302,100 GWh, accounting for 35% of the total 872,900 GWh of electricity generated in Japan that year. LNG-fired stations were the next largest source of electricity, generating 203,700 GWh, accounting for 23%. Oil-fired stations generated 154,700 GWh, equivalent to 17.7%, while coal-fired stations generated 123,700 GWh, representing 14% of power output. Hydroelectric stations, which produced 83,800 GWh and accounted for 10% of power generation, were the only other significant source of power.

In terms of installed capacity nuclear plants totalled 42,550 MW or 20% of Japan's total 207,880 MW of installed generating capacity. Oil and diesel-fired stations accounted for 52,430 MW or 25% while LNG-fired power plants totalled 49,140 MW for 24% of Japan's total installed generating capacity.

Hydroelectric stations at 42,970 MW accounted for 21% of installed capacity. In comparison coal-fired stations with 20,280 MW represented 10% of installed capacity, and geothermal stations at 520 MW accounted for just 0.3% of installed capacity.

Generation and conservation

Japan's long-term power development plans call for installed generating capacity to grow to 255,900 MW in 2010, a 23% increase compared with 1996. The need for installed generating capacity may be less than the present forecast depending on how successful Japan is in promoting energy conservation.

In 1996 Japan recorded a summer peak load of 165,110 MW. By 2010, if energy saving proves successful, the JEUIC forecasts that the summer peak load may have grown only 14.4% to reach 188,900 MW. However, if no additional energy conservation measures are adopted the total peak load will reach 223,700 MW according to current forecasts, a rise of 58,590 MW equivalent to a 35.5% increase.

To achieve Japan's Kyoto targets, nuclear power generation will increase substantially while oil-fired generation will be reduced sharply. Plans call for Japan's nuclear generating capacity to be increased to between 66,000 MW to 70,000 MW by 2010 accounting for 26% to 28% of total installed capacity.

'Most sceptics say that Japan will not reach its nuclear targets but already agreement has been reached to construct a large amount of nuclear power,' the FEPC spokesperson commented, 'By 2010 nuclear power will be 45% of generation compared with 35% now. Almost all regional utilities are building nuclear power plants. These are large plants, but away from urban centres.'

Imported LNG will remain an important fuel source for power generation. By 2010 LNG-fired power plants will have grown one-third in capacity and will be capable of generating 64,500 MW, equivalent to 25.2% of installed capacity.

'LNG will be developed as an important fuel because of its high thermal efficiency in combined cycle stations,' the spokesperson said. 'LNG offers flexibility in use. Cost is the biggest consideration, then environmental pollution control and then security of supply. LNG will continue to be developed aggressively.'

Fukushima No2 Nuclear Plant, Tokyo Electric (TEPCO), Japan

By 2010 hydroelectric stations totaling 48,000 MW will represent 19% of installed capacity. 'Hydropower potential is almost used already,' the spokesperson pointed out, 'Almost all hydropower planned in future will be pumped storage projects.'

Commenting on other fuels, the spokesperson noted that coal-fired capacity would increase to 36,000 MW in capacity accounting for 14% of installed capacity in 2010. In contrast, Japan's oil and diesel-fired stations will be reduced greatly in coming years. By 2010 oil and diesel-fired capacity is expected to have fallen to 35,900–39,900 MW, or about 14 – 16% of total capacity.

Targets source LNG

Japan's long-term electricity supply targets call for capacity to reach 1,056,000 GWh in 2010, an increase of 21% compared with 1997. To achieve this target, while reducing CO_2 emissions, nuclear generation is planned to expand to 480,000 GWh in 2010, or 45% of total power output. The second largest source of electricity will be LNG-fired generation, which is due to reach 213,000 GWh, equal to 20% of power output in that year and 3% below its current share. Coal-fired generation also will drop slightly as a proportion of total power production and is planned to reach 136,000 GWh, or 13% of total electricity output in 2010. Hydroelectric power generation will rise slightly to 119,000 GWh or 11% of output. However oil-fired power plants' share of total electricity output will be halved to 8.2%, equivalent to 87,000 GWh.

'LNG will be used for base load and mid-load generation in 2010. Oil-burning plants and pumped storage stations will be for peaking capacity,' the spokesperson said. 'Coal will be used for baseload generation. Coal-fired power output will drop by about 1% in percentage terms in future but still will increase in volume. Plentiful coal supplies are available and are economic. The drawback is the CO_2 and sulphur dioxide (SO_2) emission but there are plans to reduce pollution emissions further. In fact coal will be developed more than expected because stable and economic import supplies are available.'

Structure of electricity industry

Meanwhile, Japan's electricity industry is in a state of transition as plans to open the power generation sector to competition already are at an advanced stage with the first of a series of independent power plant (IPP) projects now due to be commissioned in 1999. Efforts to introduce competition and greater efficiency to the power sector are expected to lead to a major reorganisation of the electricity industry in the next few years.

Japan's previous electricity industry structure, which was in force until the Electricity Utility Industry Law was changed in January 1996, comprised 10 vertically integrated regional electric power companies, responsible for all stages of electricity supply from power generation through to electricity sales. Each had a monopoly of electricity supply in their designated service areas. Under the 1996 legislation new independent power producers (IPPs) are allowed to supply electricity direct to the regional utilities for distribution as well as to supply directly.

However, the new regulations do not

permit IPP power companies to build their own power distribution grids. Instead they have to supply their customers through the integrated power utilities' regional transmission and distribution grids. These regulations are now under review, with some industry observers believing that a partial opening up of transmission lines owned by existing power companies will be recommended.

'Transmission is a big issue in competition as the setting of transmission costs determines the return that the transmission line owner can get and the feasibility of IPP projects,' the FEPC spokesperson commented. 'This issue has been discussed with no result so far. This will be a major topic in the next few months as it is a vital part of the restructuring process and will reveal what degree of competition is envisioned for the electricity industry.

'The electricity industry structure is the main issue. We are now in the transition stage. Once the committee produces its report on the new structure of the electricity industry, this will set the development process for the next few years. The committee is made up of government, electricity utilities, private industry and consumer groups; so everyone has an input.'

JEUIC Committee

The task of devising a means to reorganise Japan's electricity industry was entrusted in July 1997 to the Basic Policy Committee under the JEUIC. This consists of members of government, industry, electricity utilities and consumer groups. The committee has been charged, by MITI, to devise a strategy aimed at lowering electricity tariffs to an internationally competitive level by 2001. When the review started in mid-1997 Japan's electricity tariffs were 20% higher than power tariffs in Europe but have since dropped due to the fall in the value of the yen.

The issue of tariffs is an important one for the power industry and Japan's economy in general, as many large manufacturers have cited high electricity tariffs as one of the important factors influencing their decision to move manufacturing facilities offshore to lower cost countries.

Among the initial findings was that a new system needs to be introduced to allow the entry of larger IPP thermal power plants up to 1,000 MW in future. Another finding was the need for strong measures to create a more balanced load curve, to control summer peak load demand growth.

The Committee published its interim findings in May 1998. This included a general agreement that future discussion should focus on partial liberalisation of the electricity market while the issue of complete liberalisation including the creation of a pool system as in Britain and other market models would be reserved for future study. In addition the current structure based on vertically integrated regional electricity companies should be retained.

'Under these conditions,' the Committeee reported, 'the best choice to increase competition is a realistic system of partial liberalisation based on expanded use of the existing transmission network that exploits the advantages of the vertically integrated structure.'

At present regional electricity companies generate about 85% of all electricity in Japan each year and own about 86% of the country's total installed capacity. Tokyo Electric, Kansai Electric and Chubu Electric are the three largest electricity companies. Other generators are the utilities, which sell most of their output to the regional electricity utilities for distribution. These include Japan Atomic Power Company, the Electric Power Development Corporation and others. The remainder of Japan's electricity is produced by companies with captive power generation facilities totalling about 24,000 MW.

Private sector interest in operating a power station has proven to be very large in Japan. To ensure an orderly opening to competition, two large rounds of tenders have been organised, in which prospective IPP operators have bid to supply various regional utilities.

The first round of IPP bidding was concluded in August 1997 when some 20 companies bid successfully to supply six regional utilities with a total of 3,047 MW. Nine of the IPP plants are due to start up in 1999, the rest by the end of 2002.

The second round of IPP tenders were issued in April 1998. Contracts were awarded in July, this time by seven regional electricity companies to 16 IPP plant operators totalling 3,118 MW installed capacity.

Street scene at night, Shinjuku, Tokyo, Japan

Taking marine vapour recovery monitoring systems onboard

Vapour recovery systems play a key role in ensuring the safety of volatile cargoes at sea. Every vessel carrying oil, petroleum products, solvents or other volatile flammable liquids to or from the US is obliged to have a vapour recovery system and such systems are soon to become mandatory throughout Europe. Legal requirements aside, most shipowners and harbour authorities worldwide recognise the importance of vapour recovery, and of monitoring the correct operation of the system to ensure safety. *Dr Simon Bruce* of Servomex Group looks at the technology of volatile cargo safety at sea and in port.

Vapour recovery systems for those vessels carrying oil, petroleum products, solvents and other volatile flammable liquids to and from the US must meet the US Coast Guard approval requirements for marine vapour control systems, as found in 33CFR.154 and 46CFR Part 30.* In addition, the Clean Air Act amendments of 15 November 1990 require stringent control of the emission of volatile organic compounds (VOCs) to the atmosphere. This requirement has the effect of applying marine monitoring standards to shore-based installations. The purpose of these rules is to ensure not only that flammable vapours are handled safely but also to prevent the discharge of harmful gases to the environment.

The result is that US law requires that the oxygen and hydrocarbon content of gas streams at various take-off points on the ship itself, on the shore-based storage unit and on the transfer lines are monitored. The EU Directive on emissions will require broadly the same standards, although there are some differences in detail. Norway has already followed the US standards, and other European countries are following suit.

The term vapour recovery is somewhat misleading, since the vapour is not necessarily collected, contained and re-used. Frequently, recovered vapour is disposed of by flaring or incineration. The important point is that, prior to the transfer of cargo, the vapour in the gas return lines must be either inerted or enriched to prevent the risk of combustion or explosion within the system. This is known as 'blanketing'.

Approaches to blanketing

Marine tankers are generally fitted with a shipboard inerting system along the lines of **Figure 1**. The flammability 'envelope' for a mixture of hydrocarbon gases and air is shown in **Figure 2** which shows the component ratios of oxygen (O_2) and hydrocarbons which will or will not support combustion.

For example, at point A in **Figure 2**, a mixture containing 10% O_2 and 3% hydrocarbon vapour, with a balance of nitrogen (N_2) will not burn or explode if exposed to an ignition source. A vapour mixture with 13% O_2 and under 2% hydrocarbons, as at point B, is too lean to support combustion, whereas a mixture at point C, where hydrocarbons are at 6%, is too rich to support combustion. As can be seen from the diagram, all combinations of O_2 and hydrocarbons within area D are flammable. This is the region to be avoided.

The gas or ullage space above the cargo and within the pipework of the recovery system can be made safe by any of three blanketing methods:

- *Nitrogen* is by far the most commonly used inert gas for dilution and displacement of the flammable vapours, since the resultant mixture contains an insufficient concentration of oxygen to support combustion. Usually, the oxygen content of the vapours is maintained below 8% by volume, keeping the mixture well within region A of **Figure 2**. In a marine tanker equipped with an inerting system, using scrubbed boiler exhaust as the inerting gas, the O_2 content of the gas is typically low enough to ensure that the vapours in the hold are kept within region A.
- *Enrichment* is the second most popular method of blanketing. In this process, so much hydrocarbon gas is added to the atmosphere above the cargo that it becomes too rich to support combustion.
- *Dilution* with air is the least-used system of blanketing. Air dilution reduces the proportion of organic vapours above the cargo below the lower explosive limit to the point where combustion is no longer possible. This method is often employed when personnel are required to enter enclosed spaces to inspect, weld or clean the tanks. Portable analysers are used to ensure that safe levels of oxygen and organic vapours are present before entry.

Servomex International provides vapour recovery systems for each method.

Getting the analyser right

Under the regulations, the atmosphere in the tanks carrying volatile cargo must either be at least 22.5% organic vapours or must contain less than 16.5% oxygen, depending upon the blanketing method used. Gas analysers

Servomex analyser

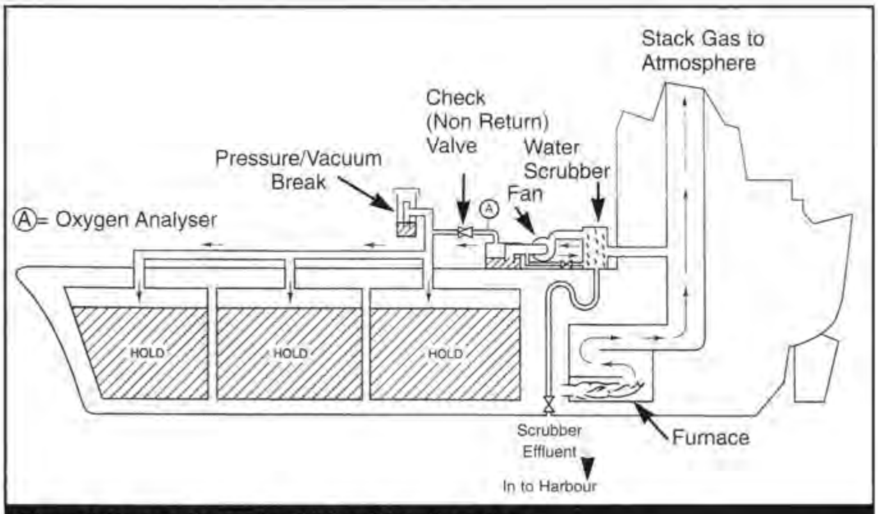

Figure 1: Ocean-going tanker shipboard inerting system

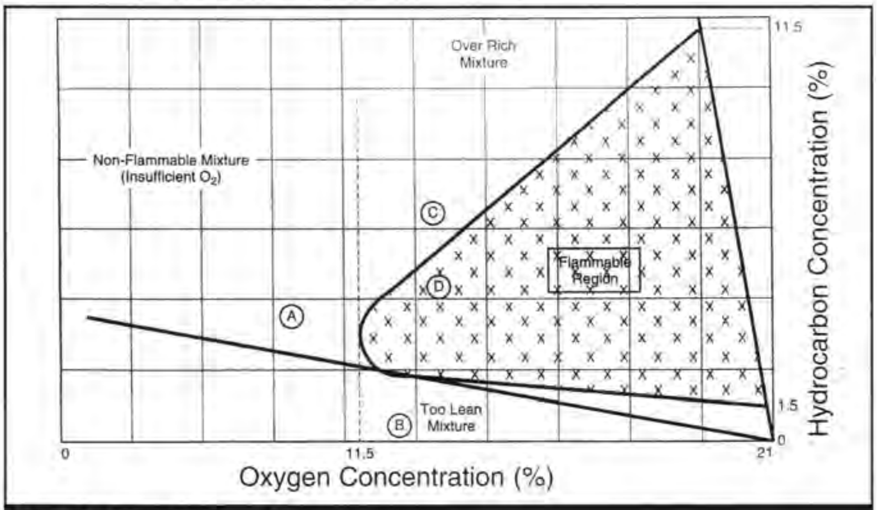

Figure 2: Flammability envelope

will either be monitoring to detect a high organic content or, much more commonly, a reduced oxygen content.

Where oxygen analysers are used, one of the stipulations is that they must not contain a potential ignition source, which rules out the use of zirconia-based instruments and hot wire analysers. However, the regulations do not address the problems associated with using low temperature electrochemical fuel cell analysers.

The truth is that electrochemical cells should be considered more as a hazard than as a benefit when used in a vapour recovery monitoring system, where shutdown is required at high oxygen concentrations and where major safety issues centre upon their accuracy and continued operation. Electrochemical cells inevitably degrade and have a finite life span. To make matters worse, electrochemical cells indicate a low oxygen level when they fail. So, unless the condition of electrochemical cells is constantly monitored, their failure will disable the vapour recovery monitoring system, putting the vessel or installation at risk.

For some 30 years, the paramagnetic oxygen analyser has been recognised as the safe and reliable approach to the monitoring of oxygen concentrations in blanketing systems. Not only does a paramagnetic oxygen analyser meet the regulations in having no potential ignition source, but it also has the benefit of being virtually unaffected by hydrocarbons and gases other than oxygen. Paramagnetic analysers provide long-term stability, are almost maintenance-free, and do not degrade.

For the continuous monitoring of hydrocarbons, or of a specific organic component of the gas stream, the best approach is to use an infrared analyser configured for the gas to be monitored, together with a sample conditioning system which cleans the gas sample before it is analysed to ensure consistency of results. An example of this is the Servomex Xendos 2500 infrared analyser, a microprocessor-controlled instrument using single-beam, dual-wavelength design with temperature controlled optics. With dual-range outputs, fault alarms, auto-calibration and a rugged IP65, NEMA 4 enclosure, the Xendos 2500 has all the capability necessary for reliable long-term analysis of hydrocarbon samples.

New developments

Despite the fact that the paramagnetic cell is so well-established and proven in marine practice, there always remains room for improvement. We recently launched a marine version of our Xendos 1800 paramagnetic oxygen analyser, which is supplied complete with its own wet gas sampling panel. The Xendos 1800 Marine provides accurate and reliable inert gas monitoring for tankers and onshore/offshore installations without risk of measuring cell depletion.

The Xendos 1800 also requires substantially less maintenance and re-calibration than competitive analysers and is extremely easy to set up and operate – making a major contribution to the speed and efficiency of docking and cargo safety, thus saving money.

The Xendos 1800 Marine can measure concentrations of O_2 from 0% through to 100% and has both 4–20mA isolated and 0–1Vdc non-isolated analogue outputs. Maximum accuracy and sensitivity is achieved by selecting one of the five oxygen measuring ranges, 0 to 2.5%, 0 to 5%, 0 to 10%, 0 to 25% and 0 to 100%. The Xendos 1800 Marine offers an overall response time of less than 12 seconds, ensuring safe operation. Oxygen concentration and sample flow failure alarm outputs are provided that integrate easily with safety and operational systems.

Advice and support

The gas analysers in a vapour recovery monitoring system are only part of a substantial system which must be engineered to meet international regulations and provide the maximum possible protection for the installation, the people working with it and the environment. Designing and installing such systems is a very specialised business.

It is therefore essential that companies whose installations need this form of protection take advice from experienced systems designers before specifying or purchasing equipment, and that one of the major companies in gas analysis is consulted about the latest technologies. Ongoing technical support is also advisable.

* *Both these documents can be obtained from Rees Howel of Servomex Group Ltd on tel: +44 (0)1892 652181.*

PESC promotes downstream training and development

January 1999 marked the official launch of a new national training organisation known as the Petroleum Industry National Training Organisation (PINTO). The body will specifically address all aspects of training and development for staff working in the downstream sector of the oil industry. *John Fuller* of the Petroleum Employers' Skills Council (PESC), the forerunner to PINTO, looks at the development and goals of the new organisation.

On 19 October 1998, UK Secretary of State for Education and Employment Peter Blunkett granted the downstream oil industry permission to set up a national training organisation (NTO) to address the training and development needs of its personnel. The resulting body – the Petroleum Industry National Training Organisation (PINTO) – is the 61st NTO to be established in the UK to date. Virtually every major industry in the UK, from engineering, communications and local government to paper production and surface coatings, now has such an organisation covering its specific training requirements.

NTOs explained

The concept for the development of NTOs began just under three years ago when the previous UK government decided that the current system of industry-based training organisations was inadequate to ensure the nation had the skills needed for the future. A whole new structure of bodies was suggested, to be called national training organisations (NTOs).

A consultative paper was received by all the existing bodies at the time, including PESC which is PINTO's predecessor. The government went ahead with a call for bids for the three-year contracts with central government under which these new bodies would operate. Just over two years ago, PESC submitted a letter stating it would bid. The bid, covering all training and development in the downstream oil industry, came in May 1997.

An election then followed, and a new government entered into power.

John Fuller, PESC

Fortunately, the initiative was a bi-party concern and, apart from changes in emphasis, the new government carried on with the NTO concept, agreeing bids and enabling new NTOs to be set up across British industry.

Bidding process

Bidding for status was a difficult process. The new bodies had to indicate a genuine commitment towards training on the part of the industries concerned. Very stringent conditions were applied and a small committee had to be thoroughly satisfied that the bid was a serious one, representing real commitment, and that the industry concerned realised what it would have to do to fulfil the contract. To illustrate the lengthy nature of these proceedings, it took PESC 18 months to achieve the status. It also had a number of conditions attached to the approval. Other bodies have also had relevant conditions relating to their industries attached to their approvals.

The bid document itself ran to 65 pages, including the strategic plan for the future. Every trade association or interest group had to be contacted and give their approval and support. It was necessary to prove that any body set up

PINTO

Petroleum Industry National Training Organisation would be really representative and would be properly supported.

A key aspect was finance. UKPIA (the UK Petroleum Industry Association), representing the major oil companies, has agreed to bear the core costs of PINTO. Additional support and revenue streams will need to be developed however, if PINTO is to succeed. This will be difficult in that any NTO has strict limits on what it is permitted to do in order to retain genuine neutrality.

What do NTOs do?

There have always been bodies responsible for overseeing training and development on an industry-by-industry basis, going back to the Industrial Training Act of 1974. For many years these were statutory bodies able to levy from employers – Industrial Training Boards (ITB). These ceased to exist (with a few exceptions) in 1982, replaced by voluntary bodies which varied greatly in terms of size and status. In the oil industry, we first had the Petroleum Industry Training Board – unique in that it was the only ITB set up entirely voluntarily by an industry. This was closed down by the government in 1982 and replaced by the Offshore Petroleum ITB and, onshore, by a voluntary body, the Petroleum Training Federation. Subsequently, the role was taken over by PESC, followed by PINTO.

Essentially, the role has remained similar throughout: to look after training and development on an industry-wide basis. More recently, this role has been extended to include putting together vocational qualifications (N/SVQs). PESC has had several accredited, with more in the pipeline.

The difference now is the very much greater call on these bodies, in the light of modern technology, and the greater requirements of central government for these bodies to fulfil national initiatives such as youth training and lifelong learning, as well as those of their industry, including standards and training.

NTOs are strategic bodies. Their strength stems from their support from business interests in their sector. This makes them uniquely valuable in a range of areas from youth training to technical standards for their industry skills.

Specifically, they have a role in:

- collecting comprehensive labour market information;
- identifying aspects of business competitiveness;
- identifying skills' shortages – current and likely future ones; and
- predicting future skills needs.

In order to achieve the above, the NTOs need to set up, where relevant, National Traineeship (N/SVQ level 2), Modern Apprenticeship (N/SVQ level 3) and Graduate Apprenticeship schemes. PESC had already moved forward in these areas, and PINTO will carry on the work. NTOs must also establish strong links with schools, further education organisations and the careers service.

NTOs have a special role in other areas too – for the production of competency standards (N/SVQs), for liaison with Training and Enterprise Councils, Investors in People in their sector, and benchmarking exercises where relevant. There will also be a strong role for NTOs in liaising with the new Regional Development Authorities.

Initiatives such as Lifelong Learning, the University for Industry, Individual Learning Accounts, and Key Skills are other areas where NTOs have a major role. They will also have a role as one of several bodies involved in areas such as New Deal, GNVQs, and National Targets.

There is, in addition, a special role for NTOs in dealing with small firms. Here there is considerable contact with the Department of Trade and Industry and there is, in fact, a Small Firms NTO with which PINTO will work.

PINTO will have to fulfil all of the above duties, the only concession being for each body to prioritise them in the light of its industry's needs. In some cases, however, the government has made it clear that every industry has a duty to fulfil its part of the national requirements to improve skills.

PINTO

PINTO will have two key government bodies with which it will need to liaise. The Department for Education and Employment will hold the contract with PINTO on behalf of government and will be its prime contact. On all aspects of standards, liaison will be with the Qualifications and Curriculum Authority which will accredit PINTO's standards.

The PINTO Board will meet twice a year. The Chairman of the Board will be the Chairman of UKPIA, currently Christian Cleret, Managing Director of Elf Oil UK Ltd. The Board will consist of a representative cross-section from the industry, including representatives from employers, staff and educational interests.

Below the Board will be the main operating body – the Management Committee. It is intended that this will include representatives from all the downstream oil companies and trade associations, relevant academic bodies and the Institute of Petroleum so that all sectors of our diverse industry are represented.

Only with the input of all can we ensure that the needs of the industry are met.

PINTO has been granted a three-year contract with central government. It has agreed milestones and targets it must achieve and will be audited by the Department for Education and Employment. If it is not effective, its contract will not be renewed. Action can also be taken in a number of ways during the period of the contract.

A helping hand

PINTO will not be able to do by itself all that has to be done, and in specialised areas agents will be used. For example, an agreement will be concluded with the Institute of Petroleum under which the IP will look after industry careers work (as it has always done). It will also assist PINTO in two other key areas: Lifelong Learning and higher level vocational and other qualifications. Additional agents will undoubtedly follow.

Like PESC, PINTO will concentrate on the non-competitive areas of training and development – legislative, safety and environmental. PINTO will go a step further, however, setting up systems to help individuals to develop themselves to achieve their goals. PINTO as a resource will be available to everyone and will be a central information point on any aspect of training and development. If PINTO does not have the information required, it will 'know someone who does' and will obtain it or assist with direct action. What PINTO will not do is offer direct training – this is not currently the mandate of NTOs (though it may change). It will, however, be responsible for ensuring that training is available in all key areas, of good quality, and being used. It will certainly give advice on training.

The future

There are, inevitably, question marks over these new bodies. For a start, they are not receiving the funding from central government that was promised. There is, though, a tremendous will to make them work. This industry undoubtedly takes the initiative very seriously with a dramatic step-up in every way from PESC to PINTO including a major increase in staffing and funding and, above all, a categoric assurance of support for PINTO from key industry interests.

PINTO officially came into operation in January 1999. It will take a few months to get into its stride and PESC will continue to exist in parallel until 31 March 1999.

A detailed prospectus of NTOs' roles and the PINTO workplan are available from PINTO at the Olympic Office Centre, 8 Fulton Road, Wembley HA9 0ND, UK.

Trends freeze in winter diesel market

One of the key continuing trends worldwide in diesel fuel production is the reduction in sulfur content due to environmental concern and consequent emissions regulation. In addition, with the growth in low sulfur fuels, lubricity is increasingly an issue. However, cold flow parameters and cetane levels (with the exception of Japanese fuels) have remained largely unchanged over the last year, according to the latest data published in the *Infineum* (formerly Paramins) *Worldwide Winter Diesel Fuel Quality Survey*.

The past year has been marked by prolonged debate in Europe over new vehicle emissions specifications which will have far reaching consequences for the oil industry. 1998 also saw the publication of a Worldwide Fuel Charter – a proposal for harmonising fuel standards across the world. The Charter was produced by the three automotive industry associations which represent most of the developed world: the American Automobile Manufacturers Association (AMMA), the European Automobile Manufacturers Association (ACEA), and the Japan Automobile Manufacturers Association (JAMA).

Sulfur reduction continues to be the major focus of fuel regulation. Indeed, as regards the latest proposals from the European Union, the draft directive on fuel qualities for 2005 has yet only one firm figure for diesel – that of sulfur emission limits.

Diesel fuel survey data since 1992 has tracked this sulfur reduction trend. In 1992 the majority of countries sampled had average sulfur contents of between 0.1% and 0.5%. By 1995 this was down to between 0.05% and 0.2%. The latest figures show a further reduction to between 0.001% and 0.05% for the majority of countries – less than one-third of the 36 countries surveyed had average levels above 0.05%.

The current European specification EN 590 lays down a maximum of 0.05% sulfur content. This target is being met by all the countries subscribing to it (including Portugal which has improved its performance in this respect since the 1997 survey) and many are already meeting the year 2000 requirement of 0.035%.

Even those European countries not bound by EN 590, such as Russia and Poland, are reducing their average sulfur contents, although they have not yet achieved the 0.05% level.

This downward pressure on levels will continue and is, in fact, set to intensify. While the new European specification for 2000 will be a further large step along this path, the year 2005 requirement is for a maximum of 0.005% sulfur content. The European Commission and Council of Ministers had originally set this target as an 'indicative' figure, one that was to be used by the industry effectively as 'best performance'. However, at the end of a formal 'conciliation' process, the Parliament had to accept the less stringent Council target levels, while the Council had to accept the figures should be mandatory rather than merely indicative.

Impact on refining

This will have important consequences for the European fuel industry. Currently, refining is relatively low and there is a significant over capacity (in the order of 10%) in the market.

Now that some performance levels have been agreed (although currently a number of the diesel parameters remain uncertain, such as distillation, aromatics content, cetane number and density) refinery operators will be able to make decisions on the future viability of their plants.

Most European refineries will not be able to meet the 2005 figures without substantial investment: a number will be unable to achieve the 2000 requirements. Removing more sulfur and aromatics will mean more severe hydrofining and hydrogenation. Billions of dollars will need to be invested each year to give European refineries the ability to meet the 2005 standards. This will undoubtedly mean some rationalisation and plant closures. The decisions as to which ones may not be made on purely commercial grounds, though. There may be instances where political pressures dictate investment in one plant rather than another.

Outside Europe, sulfur levels have continued to fall, with Korea and Taiwan adopting a 0.05% limit (although the measure was introduced after the data for the survey was collected). The environmental agenda is driving through measures to reduce emissions throughout the Asia-Pacific region, despite the severe economic downturn. Both Hong Kong and Japan have reduced sulfur levels to less than 0.05% since the 1997 survey.

Lubricity

As the number of low sulfur diesel fuels increases – and the sulfur content decreases – lubricity is becoming an ever more important issue. High Frequency Reciprocating Rig (HHFR) measurements are now available for the past three years. These show a tendency to lower lubricity in samples from the US over that period. Over the last year, however, lubricity has improved in all three grades of Japanese fuel, following agreement on a limit of 460mm HFRR wear scar limit.

In Europe, where a 460mm limit is being introduced, there has been little change since the 1997 survey. Switzerland, however, has improved its results – the mean of the samples being within the limit value. Only six countries have results below this limit in all the samples collected while Greece, Italy, Denmark and Norway had an average HFRR result above 460mm.

Cold flow

The new survey shows that cold flow parameters have remained largely unchanged since 1997, although there are occasional local differences. In Finland, for example, all fuel samples show characteristics more commonly associated with arctic use – this may be due to some rationalisation of grades.

Cetane

The European 2000 specification sets a minimum cetane number of 51. However, despite the fact that the last survey showed nearly 75% of all European samples failing to meet this target, there has been virtually no change in cetane levels in the intervening 12 months.

The only notable changes have been to the colder climate fuels made in Japan.

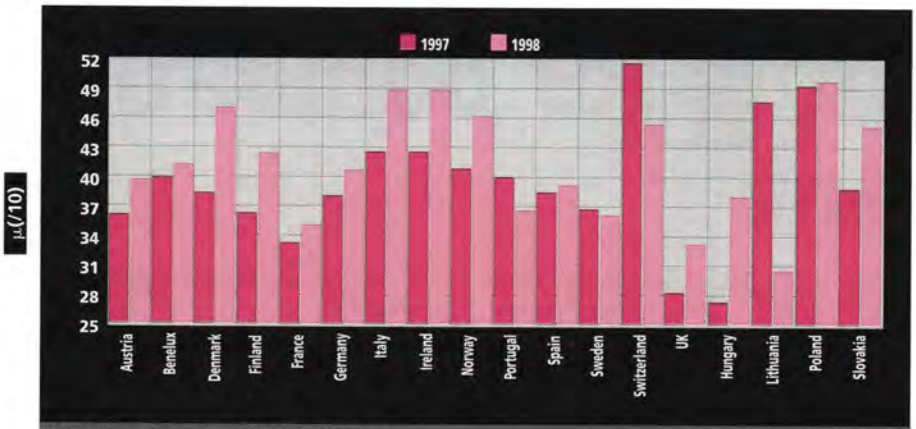

Figure 1: European trends in HFRR

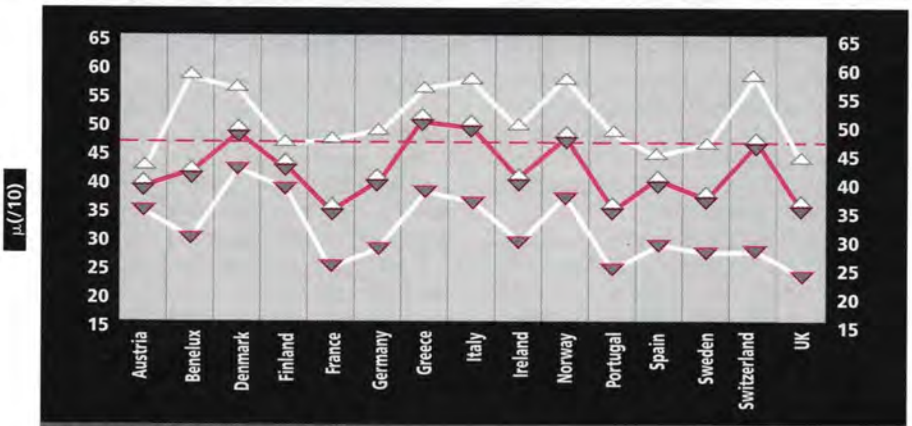

Figure 2: European trends in HFRR

The 14th edition of the *Worldwide Winter Diesel Fuel Quality Survey* brings together data from 296 diesel fuels collected from service stations in 36 countries around the world. These were analysed at laboratories in the US, Japan and the UK.

In general, one sample is obtained from the production of each refinery or region in a given country. To minimise the possibility of taking multiple samples from a single refinery, the company used its knowledge of local exchange agreements and distribution systems to carefully select the area in which to collect the sample.

For the majority of countries, samples were collected during the northern hemisphere deep winter months of January and February 1998. For those southern hemisphere countries producing winter grade diesel, sampling was delayed until later in the year when winter grade samples could be obtained. ●

Both the Grade 3 and the Special Grade 3 fuel show considerable improvement on the previous year's figures.

Density

Of samples taken in the UK and in Portugal, the mean value for fuel density is still above that of the new European specification. In several other EU countries some samples were still above the required level.

Fuels of the future

The economics of change in regard to reducing sulfur content have already been mentioned. The survey has plotted the collected data against the requirements of the year 2000 specification. It shows that changes will be required, mainly in Greece, the UK, Portugal, Spain and Italy. However, it should also be noted that the survey covers winter fuels only – when summer fuels are added, more widespread action will be seen to be necessary.

Some of the radical changes to fuels being considered, particularly in the European Parliament, and also in the light of markets with advanced emissions controls such as California, will require a significant re-engineering of fuels. This will mean that the fuels of the future will behave differently from the currently available grades. Quite how the performance characteristics will change is not yet certain as the limiting parameters are still being discussed and decided (the delays have already interrupted the Auto Oil II programme).

The role of additives is also under discussion. For example, the European Parliament wants fiscal incentives to encourage the use of fuel additives, while the Council of Ministers remains unconvinced of their overall environmental benefits.

What can be said with certainty is that the fuel industry is about to embark on a period of rapid change as new stricter limits on emissions and performance are introduced, not just in Europe, but around the world. ●

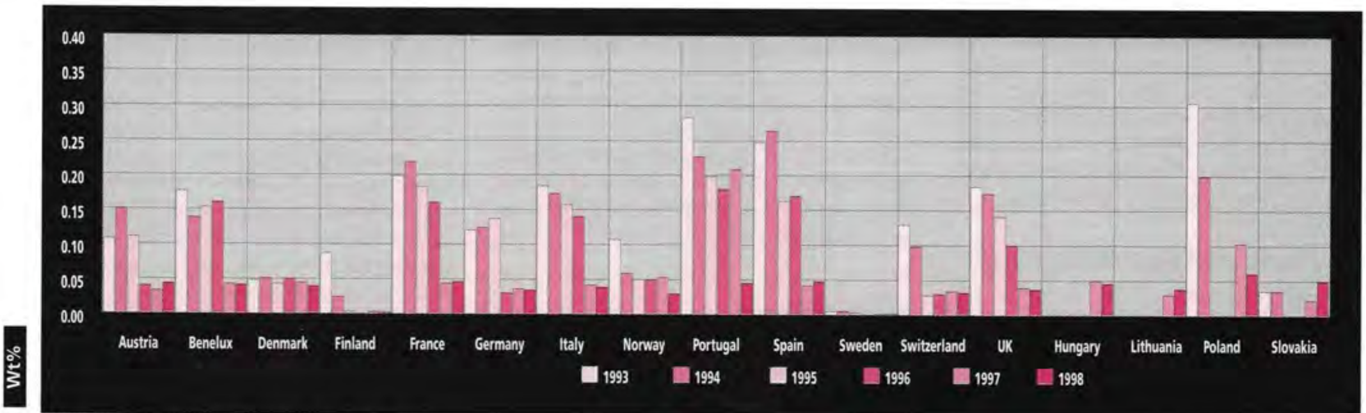

Figure 3: European trends in sulfur levels

The tide turns for domestic development

Interest in North Korea is beginning to increase as western oil exploration companies advance investment plans and as South Korea's Hyundai adds new impetus to these efforts, writes *Alex Stewart*, an investment strategist recently returned from a fact-finding mission to the hermit state.

North Korea is *terra incognito* as far as most investors are concerned. Yet under the pall left by the negotiations over nuclear facilities and missile launches, North Korea is a country desperately trying to do business with the outside. Not because it wants to become part of the outside world, but because its economy needs hard currency and new technology. Otherwise it will come crashing down, and with it the regime.

The most illuminating example of the business-mindedness of the regime occurred at the end of November 1998, when the Honorary Chairman of Hyundai, Chung Ju Yung, visited North Korea, met the Great Leader Kim Jong Il, and gained a seal of approval for investments worth tens of billions of dollars. The uniqueness of this lay not just in the fact that the deals received the royal signature, but that they also had the blessing of the government in South Korea, which until last year had barred both large-scale investment and investment in strategic sectors like energy.

South Korean participation

The participation of the large South Korean conglomerates, especially Hyundai, whose founder came originally from the North, and which has long sought to obtain the inside position ahead of unification, is very significant as no other country is willing to commit long-term risk capital to the same extent. The conglomerates believe that in the long-term a strong position in North Korea will be vital for the successful development of their domestic business in the twenty-first century. They are therefore willing to invest in high-risk infrastructure areas, such as power and transport, which most western investors shun. It is only by investing in infrastructure, however, that large-scale resource projects stand a chance of being developed satisfactorily. Hence southern investment is vital to make North Korea a half-attractive location for investment.

North Korea's desperation for energy (and the hard currency to buy it) dates chiefly from the collapse of the Comecon trade system in the late 1980s. Until that time it had enjoyed access to energy on highly concessional terms. This had an unhelpful side-effect of encouraging the economy to use energy wastefully, so making it highly energy-intensive. In 1990, North Korean consumption of primary energy per capita was 67 gigajoules, which was three times higher than the equivalent Chinese level, and only half the per capita level of Japan.

North Korea sought even so to maintain independence *vis-à-vis* the Soviet bloc by developing indigenous coal reserves. Unlike China however, it did not have the ability to exploit indigenous reserves of oil and gas and hence could not avoid dependence on the Soviet Union for these key inputs. After 1969, with the help of Chinese geologists it began investigating for oil and gas in the offshore sector, especially in the Bohai Basin which extends into North Korean territory. However it lacked the technology to explore the basin thoroughly. As with the other strategic sectors of the economy moreover, it depended heavily on Soviet technology to locate and exploit oil and gas reserves, and the presence of Soviet engineers to supervise maintenance and operation.

Barter trade

When the Comecon system collapsed, North Korea lost access to both these strategic fuels and to Soviet technology. It also lost a market for its goods. This caused a massive contraction in production, while North Korea's unpaid debts to Western, Russian, and Japanese banks and suppliers made it almost impossible for it to receive hard currency credits for imports from the rest of the world, other than 'rogue states' in the Middle East and Africa. The absence of hard currency means it continues to conduct trade on a barter basis. Each year though this is becoming harder to do, as production at mines and other facilities becomes shut in due to a lack of raw materials, fuels and parts.

The contraction in the economy caused the supply of primary energy to fall by 36% between 1990 and 1996, according to the Nautilus Institute of the US which provides information on North Korea for the US policy community. Imports of energy fell to by 50% (see **Table 1**). The ratio of energy self-sufficiency increased as a result from 90% to 95%. The cost to the economy of such self-inflicted 'self-sufficiency' is extremely high. The fact that the household sector accounts for 16% of energy consumption, and transportation a tiny 2%, provides a snap-shot of how it has created immobility in the economy and a low standard of living.

Attracting outside interest

The regime knows that it cannot go in survival mode forever, hence its desire to attract inward investment, especially into the energy and mining sectors, which can earn hard currency. Paradoxically North Korea is as a result more open than press reports tend to imply. It struggles against the fact however that the US does not encourage openings to trade with the North by maintaining its post-war sanctions regime. This in turn makes its key allies in the region, especially Japan, wary of engagement. Europeans are free to conduct business but are hampered by the lack of interest shown by the US, Japan, and until recently, South Korea.

Countries not prohibited from doing business with North Korea still have to decide whether the opportunity cost and perceived risk is worth it. The Asian economic crisis has increased the attractiveness of alternative pickings in South East Asia, where the perceived risk is lower too. To compete, therefore, North Korea must offer investors even more attractive terms. Even then it is handi-

Primary energy supply, 1990 *(Petajoules)*

	Coal & coke	Crude oil	Refined product	Hydro/ nuclear	Wood/ biomass	Elec.	Total
Energy supply	1,356	111	27	77	382	(12)	1,940
Domestic production	1,318	–	–	77	355	–	1,750
Imports	68	111	27	–	–	–	232
Exports	30	–	–	–	–	12	42

Primary energy supply, 1996

	Coal & coke	Crude oil	Refined product	Hydro/ nuclear	Wood/ biomass	Elec.	Total
Energy supply	735	43	33	14	413	(1)	1,236
Domestic production	775	–	–	14	386	–	1,175
Imports	8	43	39	–	27	–	117
Exports	48	–	7	–	–	–	49

Source: Nautilus Institute, David Von Hippel, Peter Hayes

Table 1: Primary energy supply in 1990 and 1996

capped, because it cannot demonstrate as yet a track record of successful investment by a foreign company.

Activity offshore

There is one area however where foreign companies are beginning to build up a store house of favourable experience, which is in the offshore oil sector. Over the last five years three production sharing contracts have been signed, two of them in the last 18 months. These relate to two concessions on the West Korean Bay and one on the East Sea side. The three companies involved – Taurus Petroleum of Sweden, Beach Petroleum of Australia, and SOCO International of the UK – have all obtained extremely generous contracts, which specify no payment of taxes or royalties, and a production split in favour of the investor in the early stages of production.

The West Korean Bay is an extension of the Bohai Basin off China where 450mn barrels of recoverable oil have been found according to Wood Mackenzie's *South East Asian Upstream Survey*. Recent exploration activity in the Chinese sector located several new fields in 1998. The promoters of oil off North Korea are clearly hoping that they will make similar finds over the next two years as their drilling programmes proceed. All three companies are currently looking for investors to fund the next step in their exploration programmes. The offshore could hold several billion barrels of oil according to ethnic Korean middlemen who are actively promoting investment, especially among the South Korean *chaebol* conglomerates.

Refining impact

The North Korean government would ideally like to take its share of production in crude oil rather than dollars and process the crude at its two refineries. These are located close to the Chinese and Russian borders, on the west and east coasts respectively. They have combined throughput capacity of 60,000 b/d, which is approximately what North Korea consumed in 1995 according to US Department of Energy (DOE) statistics. In 1995 the DOE calculated that North Korea imported around 20,000 b/d of refined product, suggesting that it processed the balance of 40,000 b/d itself. However it seems unlikely that in 1998 it processed nearly this amount, owing to the steady deterioration of the refineries through lack of maintenance.

While it would be the North Korean preference to refine its own crude it seems unlikely that it will be commercially viable to do so, as its two refineries are effectively obsolete, having been built in the 1960s to prevailing Soviet standards which were then already many years behind the West. On the North's doorstep, moreover, are huge modern refineries in South Korea, which have massive economies of scale and excess production.

The Seungri refinery at Sonbong on the Russian border has a locational advantage in being near the products-deficient Russian Far East. Sonbong also forms part of North Korea's only Free Trade Zone which offers tax and other incentives to foreign investors. The principal promoter of an investment in this refinery is the US consulting group, Stanton, which has organised feasibility studies of the plant for several US oil majors. Stanton claims it would be commercially attractive to combine investment in the refinery with the oil-fired power station next-door, since the power plant could obtain a low-cost source of fuel, while the refinery could invest in new cracking equipment to produce lighter yields for export to the Russian Far East. Lukoil expressed interest at one point in cooperating in this plan by offering to supply crude oil for the refinery (either directly or swapping it for local Asian crude) and taking the refined product to sell more cheaply in the Russian Far East where buyers pay a high premium for locally-refined product due to transport distances.

Despite occasional South Korean press reports to the contrary, Stanton claims that it has made no real progress with this plan to date. The best the Seungri plant has achieved to date is to export two cargoes of naphtha to South Korean petrochemical companies, with LG International serving as intermediary for the transactions. The sale was probably opportunistic: a 'cheap' batch of crude evades Russian customs; the refinery is fired up for a month; the processed output sold into the permanently-short South Korean market for naphtha; while the Russian middlemen and North Koreans share the pay-off. In this way the plant functions sporadically at best. It no longer supplies the next-door power station, which obtains its fuel oil instead from the US-led nuclear power consortium known as KEDO (Korean Peninsular Energy Development Organisation) under the Framework Agreement signed in 1994 to supply light-water reactors in return for a freeze on the North's nuclear development programme.

At the time of the agreement North Korea had in operation a 20 MW nuclear reactor and a 5 MW pilot reactor, both of which it closed down under the Framework Agreement. The agreement stipulates that KEDO supplies two light-water nuclear reactors with a combined capacity of 2,000 MW and 500,000 t/y of fuel oil as compensation for the loss of power. After four years of slow progress agreeing the financial terms of the deal, however, the target date for completion has slipped back from 2003 to 2008, which is hardly helping North Korea's energy situation. There are other ways of supplying the energy, at a lower cost, including the Vostok Plan, which was proposed by the former Soviet Union as a way to transport gas by pipeline from the Russian Far East to South Korea via North Korea. At the time that this was actively canvassed in the late 1980s, Hyundai was its most enthusiastic proponent.

The Sonbong power station is the only significant-sized power station which relies on oil. Other power stations use a certain amount of crude oil to increase the burn point in their coal-fired plants, most of which they receive from KEDO. Coal accounts for 75% of fuel used; oil only 4%, and hydro the rest. For the most part North Korea has to rely on its spirit of self-sufficiency (now a forced virtue) to build small power stations and especially mini-hydro facilities to make up for failures in the grid system. This is inadequate to maintain power to large industrial enterprises. One steel plant has managed to finance the construction of a 5 MW power station supplied by Wartsila Diesel of Finland, through a mixture of cash payment (70%) and bartered pig iron (30%). Hyundai is now in negotiation to supply a 100 MW power plant to Pyongyang, which will be paid in a similar mix of hard currency and bartered goods.

Problems of debt

The absence of a credit rating, caused by North Korea's bad debt situation, makes it almost impossible for North Korea to purchase equipment using bank credit facilities. Despite North Korea's requests to join both the Asian Development Bank and the World Bank neither are keen to admit the country until its standards of accounting and its relations with the US improved. The only multinational so far to brave the waters is Shell, which has an option to build a tank farm on a piece of land which it has been renting in the Rajin-Sonbong free trade zone. It is proposing to share investment costs of \$6mn with outside equity investors. The tanks will store bitumen for sale to China's Yanbian province where large-scale highway construction projects are underway.

The absence of hard currency has not deterred other companies from seeking to do business, in the belief that an investment in strategic sectors like power will put them in a stronger position to win mandates after the North begins the process of formal, forced, or ad hoc integration with the South. Hyundai is in the forefront of such investors. So far it has gained goodwill by pulling off a tour deal to the North in return for pledging to pay \$906mn over six years. At the end of 1998 Hyundai's Chairman paid his third visit of the year to discuss other large-scale projects, including the power station for Pyongyang.

The arrival of Hyundai on the scene, after 10 years of patiently waiting to receive a green light from both North and South could now change the investment outlook for North Korea dramatically. Traditionally the natural resources of the North such as coal, iron ore, copper and magnesia, were processed by plants located close by. The South's heavy industry companies are now keen to invest in the North's natural resources and process them in the South in order to gain the advantage of lower transport costs and to obtain favourable investment terms on the assumption that the North will offer tax breaks and other concessions to facilitate investment.

Future potential

One of the most compelling scenarios to imagine is that oil exploration yields similar large finds to China's Bohai Bay. After 15 years of development Bohai is producing approximately 70,000 b/d according to Wood Mackenzie, which would be significant in the context of North Korea's current oil consumption.

Alternatively it would enable Hyundai to promote its proposal to build a subsea pipeline the 50 km to 100 km distance to its refineries on the West Coast, and so create the first symbolic physical link between the two countries.

So long as Hyundai is allowed to advance such plans there is a chance that it may help to turn its dreams of a unified economic space into a reality.

100 years old but still yielding new prospects

With emerging markets angst gripping the world, a look at the more traditional homepatch oil and gas plays, such as Texas, seems appropriate given its proximity to the largest hydrocarbon consuming markets in the world. Texas accounts for nearly 20% of the world's producing oil wells and remains the largest single producing region in the US. Despite large-scale production throughout this century the state still has considerable potential in terms of new horizons and more effective exploitation of known deposits, writes *Priscilla Ross*.

In the last six months of 1998 Texas accounted for 22% of US oil production and 32% of marketed gas production. One out of every five producing oil wells in the world is located in Texas. The oil and gas industry contributes around \$60bn/y to the Texan economy – or roughly 10% of the state's economy. In addition, the industry pays around \$1bn/y of indirect taxes and over \$820mn/y in severance taxes.

In late December 1998 *Petroleum Review* was told by Phil Wilson, Director of Communications for the Railroad Commissioner, Charles Matthews, who regulates the oil and gas industry in Texas, that the Commissioner was 'exploring and promoting a moratorium on the severance tax because of the current low oil price scenario'. According to Wilson there are currently 453,000 personnel employed in the Texan oil and gas industry – a substantial contraction from the 980,195 jobs in 1982.

The severance tax is based on the sale price of product. Wilson explained that Texas was ready to start a legislative session and 'if the bill passes we will hopefully have some relief shortly, but it is up to the legislature what they will do'.

The severance tax is levied at a rate of 4.6%/b on oil and 7.5%/mn cf on gas. A source close to the Texan oil industry suggests that the severance tax only makes economic sense when the oil price is over \$15/b.

Robust demand

Hydrocarbon demand in the US remains robust, especially given the strength of the US economy. According to the latest *BP Statistical Review of World Energy* US demand accounts for 25% of global oil demand and 28.8% of global gas consumption. Over the last ten years US oil production has declined by 18% and now covers only 45% of US crude requirements.

In contrast, natural gas production has increased by 13.6% over the period and meets around 86% of US gas demand.

Large reserves in Permian Basin

Remarkably, three-quarters of Texan oil output and 18% of US domestic production comes from the Permian Basin in west Texas. Despite being in production since 1889 the region is still regarded as prospective. Some 78% of Texas oil reserves are in the Permian Basin. These proven reserves amount to 4.5bn barrels, accounting for 20% of the entire reserve base of the US, according to the Railroad Commission.

In 1997 Texas produced 5.84tn cf of gas. Some 24%, or 1.38tn cf, of this came from the Permian Basin. The Railroad Commission is very positive about Texas gas availability in the long term. It is very accessible and relatively easy to find with the advent of 3D seismic visualisation and computer-aided drilling techniques. Recovery by horizontal drilling with multiple connectors is also improving recovery rates.

Wilson said in late December 1998 that around 8,820 new oil and gas permits had been passed by the Texas Railroad Commission compared to 12,824 in 1997. More gas drilling permits were passed but the numbers were fairly evenly distributed between the two sectors.

Gas prices were regarded by Wilson 'as fair not great. The separation of oil and gas prices is a new phenomenon and we are not sure how long this will continue but gas prices remain fairly stable'. East Texas and South Texas are the most productive areas for natural gas in the US. Wilson believes Texas has gas resources for the next 85 to 100 years.

The premier producer in the Permian Basin is the Altura joint venture between Shell and Amoco. Texaco is the second largest producer in the Permian Basin, employing about 650 people in the area, and produced about 125,000 boe/d in 1998 (around 71,000 b/d of oil and 325,000mn cf/d of gas).

Holding its own

With increasing focus on profit centres rather than cost centres the Permian Basin is holding its own. Texaco's operations in the Permian Basin are reported to have contributed 15% of earnings and notched up a 24% return on capital employed (ROCE) in 1997.

Although not as severely affected as oil prices, for the third quarter and first nine months of 1998 average natural gas prices were \$1.89/mn cf and \$2.03/mn cf, some 11% lower than the 1997 periods as the result of excess supply in the marketplace.

The flat terrain of the Permian Basin means that seismic can be bought for \$7,000 to \$25,000 per square mile. Geology allows a rig to drill a 12,000 feet (3,660 metres) well in under a month. Advanced recovery methods are squeezing additional reserve life out of what were considered mature declining fields. Production has been growing significantly with the use of enhanced oil recovery technology and in particular more recently carbon dioxide (CO_2) injection.

Typical of the region, the Sundown Slaughter oil field was discovered in 1937 and water flooded in the late 1950s. Primary production recovered little more than 10% of the oil in place. Water flooding helped to produce an extra 30% and in 1994, with the first phase of CO_2 flooding, a further 14% became producable. Currently the field is producing 7,000 b/d of oil and, of this, 4,700 b/d is derived from CO_2 injection.

Horizontal wells have also found their niche replacing vertical producers and working in tandem with CO_2 injection. Horizontal wells can now be drilled at up to 500 t/d (150 m/d) with downhole monitoring now routine and the technology still developing and advancing.

The Bryant G Devonian field was discovered over 30 years ago and has recently undergone 3D seismic evaluation for identifying the best reservoir quality. Horizontal drilling technology has been introduced to lift production ten times in two years.

The Australian junior Bligh Oil & Minerals is participating in the Crossroads and Roosevelt plays in the Permian Basin. According to Neil Malloy, Chief Executive Officer of Bligh Oil, the rationale behind the company's activity in the US is:

- The US provides the opportunity to work effectively at large working interest levels with small capital expenditure budgets.
- The country offers the world's shortest periods between discovery and cash flow and the world's highest netbacks to the producer at low production rates.
- It also offers the most easily quantifiable technical and financial risk of any oil play around the globe.
- Joint venturing is a long-standing business practice.
- There is a hyperactive farm-out market.
- This level of market sophistication also means that there is an easy and accessible resale market for proven reserves if funds are required to be invested elsewhere.

However, Malloy points out that there are very few company-making project opportunities available for new entrants. Reservoirs have high decline rates and the treadmill effect is a common feature of the business, as is the intense competitiveness.

According to Bligh Oil, gas plays are very deep, typically at depths of 4,000 metres to 5,000 metres (13,000 to 16,250 feet) in the gas prone areas of Texas and Oklahoma.

The company claims that analysis of the cash flows from producing properties would suggest that the Morrow play in the Anadarko Basin of Texas and Oklahoma can be valued at between \$1mn to \$1.5mn per bn cf of proven reserves. Per well reserves range from between 3bn cf to 50bn cf per well and deliverabilities up to 20mn cf/d. Well costs are in the range of \$1.6mn to \$2mn completed.

These sort of projections tie up with the Bryant G Devonian field achievements where natural gas production has burgeoned from 5mn cf/d to 50mn cf/d. Some 41 wells have been drilled since 1996. Oil production is now 2,000 b/d against a previous 300 b/d. Natural gas liquids per day output is 6,500 b/d against a previous 600 b/d.

Chevron, the third largest US gas producer, reported a 120% replacement rate for its hydrocarbon production in 1997 in the US – the highest rate since 1984. Chevron completed 25 new wells in the Laredo area of South Texas in 1997 compared to 34 in 1996. These additions mean that the total well-bore count in the Laredo area is 294, of which 168 have been based on 3D seismic acquisition and prospecting. In 1997 new proved gas reserves amounted to 66bn cf compared to 88bn cf in 1996. Over the last five years Chevron has added proved reserves of 400bn cf. In 1997 gas production averaged 135,000mn cf/d. In 1998 the plan was to drill a further 30 wells; the average new proved gas reserves each year for the last five years has been 80bn cf.

New lease of life

Mature oil and gas fields are being given a new lease of productive life, particularly in the Permian Basin and, in gas, new economic discoveries are being made productive in the dash for environmentally clean gas. The low oil and gas prices are hurting and it remains to be seen whether the Texas state legislature will bend to lobbying from the state's largest economic contributor and the second largest employer, the oil and gas sector to sanction a moratorium on the severance tax.

Rank	Producer name	Annual production %(barrels)	Daily average production (barrels)
1	Amoco	8.10% (40,137,089)	109,664
2	Exxon Corp	5.90% (29,215,774)	79,825
3	Shell Western	4.50% (22,300,219)	60,930
4	Marathon Oil	4.09% (20,269,378)	55,381
5	Texaco	3.82% (18,918,878)	51,691
6	Mobil	3.81% (18,880,420)	51,586
7	Chevron	3.41% (16,908,787)	46,199
8	Parker & Parsley	3.07% (15,208,330)	41,553
9	Amerada Hess	2.68% (13,250,518)	36,204
10	Union Pacific	1.87% (9,250,077)	25,273

Table 1: Largest oil producers in Texas in 1996

	Oil (,000 b/d)		Gas (bn cm)	
	Prod*	Consumption	Prod	Consumption
1987	9,945	16,025	479.8	496.9
1988	9,765	16,630	492.8	519.5
1989	9,160	16,665	499.7	542.8
1990	8,915	16,305	514.2	540.3
1991	9,075	16,000	510.4	549.0
1992	8,870	16,260	514.5	563.7
1993	8,585	16,470	520.4	583.2
1994	8,390	16,950	541.8	596.1
1995	8,320	16,950	534.9	620.6
1996	8,295	17,470	540.4	631.7
1997	8,255	17,735	545.3	632.5

* Oil and liquids

Source: *BP Statistical Review of World Energy 1997*

Table 2: US oil and gas production and consumption

Assessing the risks

Floating production, storage and offloading vessels (FPSOs) have become the preferred option for oil fields around the world. There are around 45 such units operating in both shallow and deepwater at present: Asia (13); Australasia (6); Brazil (5), the North Sea (15) and Africa (6). Some analysts suggest that by 2000 the figure will rise to around 130, although this may be cut back due to the continuing low oil price. Yet in the deepwater Gulf of Mexico, an area of increasing E&P importance, there is not one FPSO. However, moves are afoot which may lead to a change in this situation, possibly by the end of the century, reports *Neil Potter.*

According to the Minerals Management Service (MMS), which oversees operations in the region, no operator has put forward an FPSO project for approval to date. Indeed, there is currently only one FSO (floating, storage and offloading unit) in use – Pemex installed the *Ta-kuntah* in the Cantarell field in the Bay of Campeche in 1997 in 85 metres water depth. This has storage for 2.2mn barrels and dual offloading systems, side-by-side and tandem, with the capability of simultaneously offloading into two shuttle tankers.

There are also concerns that the MMS may not yet have sufficient understanding of FPSO technology and operations to be able to determine the level of environmental impacts that will, or have the potential to, occur. Environmental issues play a key role in the Gulf, a region associated with unusual currents, severe storms and hurricanes, and concern over oil spills.

As a result, for some time the MMS has been studying FPSO issues with operators, equipment suppliers and FPSO operators. It has sent personnel to the UK and Norway to discuss operations there and is to begin an Environmental Impact Statement (EIS) in March 1999. It is planned to complete a draft report in December with the final report available in August 2000. The Deepstar project – a joint industry study initiated by Texaco six years ago – is also now looking into the issues involved in FPSO operations in this region (see *Petroleum Review*, August 1997).

Bechtel and Safetec of Norway have been working on a two-phase joint industry project (JIP) to determine the risks associated with the development of an FPSO system in the Gulf of Mexico. Ten oil companies, three FPSO contractors, four certification agencies and the MMS are sponsors, with the US Coast Guard participating as an observer.

Some of the JIP first-phase results will be published in May at the 1999 OTC (Offshore Technology Conference) in Houston. The second phase – which will include risks and consequences to the shuttle tanker, drilling rig and transportation, such as the helicopter, as well as identifying critical FPSO components that need more detailed evaluation – is due to start in March 1999.

Dr Demir Karsan and Dr Rajiv Aggarwal of Bechtel and Jon Daniel Nesje of Safetec explained the work done so far at a recent IBC conference in London. They point out that there are more than 4,000 offshore platforms and about 20,000 miles of pipelines of various sizes installed in the US Gulf of Mexico. Up to 305 metres water depth, the majority of these installations are steel jacket platforms or tripods. Shell holds the deepest water depth record for a fixed platform with Bullwinkle in 410 metres. There are 10 production facilities installed in water depths up to 1,000 metres. All current deepwater platforms are located reasonably close to an existing pipeline network and do not require offshore storage and/or shuttle tankers.

The MMS has recently awarded a significant number of deep and ultra-deepwater leases that extend to 3,400 metres depths. The existing pipeline network is generally far away from most of these, so, coupled with the technical difficulties inherent in installing and maintaining large diameter pipe at these water depths, offshore storage and transportation using shuttle tankers becomes an economically viable and advantageous option.

Current absence of FPSOs

Some of the reasons for having no FPSOs in the region, apart from the fact that no operator has submitted a plan, are public and US government reaction to a number of oil spill pollution incidents and the fact that the MMS does not allow gas flaring in US waters.

In addition, FPSOs have a number of components and features for which no Gulf of Mexico experience currently exists. For example, present Gulf of Mexico operational philosophy requires evacuation of all personnel before a hurricane – this leads to concern about abandoning a fully operational ship in the path of a hurricane. The government agencies and operators need an assurance that the risks associated with FPSOs are not higher than the comparable systems in shallower water.

Risk assessment of production systems is not a regulatory requirement in the Gulf of Mexico. The JIP outlined earlier is the first detailed, voluntary, industry-wide application of risk analysis to a FPSO system in US waters.

Phase One objectives included:

- demonstration of the acceptability of FPSO risks in the Gulf of Mexico;
- identification of accidental events and FPSO components with loss of life, high environmental pollution and financial loss consequences;
- recommendation of reasonably practical (cost effective) measures for reducing risk; and
- the development of requirements for a permanently manned FPSO.

Base case scenario

The base case system involved nine subsea wells located 3 km from the FPSO to allow drilling and well completion operations by a separate rig. The ship is located 150 miles from the nearest shoreline, 30 miles from shipping fairways and the closest shipping route is two miles distant. Water depth is 1,300 metres, production at 80,000 b/d, utilising a converted vessel with a permanently turret moored system and a crew of 35. Oil is exported by shuttle tanker and associated gas by subsea pipelines.

The following exclusions were made to the base case risk analysis: no gas lift, no thrusters and dynamic positioning system, no standby vessel, no tug assistance during offshore loading and no ROV (remotely operated vehicle) on the FPSO. The effects of some of these excluded options are being evaluated in a sensitivity risk analysis task.

The project started with a Preliminary Hazard Assessment (PHA) of a basic FPSO design using a converted tanker. This was followed by Quantitative Risk Analysis (QRA) on high-risk events as identified in the PHA. During this work various risk reduction measures were identified, and improved layout and sub-system designs recommended.

Ten events/hazards were identified as 'high' risks for one or more consequences. These included:

- process leaks leading to escalating fire and explosion events;
- blowouts from subsea wells;
- collision from passing vessels, supply vessels and shuttle tankers;
- failure of the mooring system;
- leaks from risers and flowlines leading to fire on the sea;
- loss of gas/oil riser;
- explosion in cargo and ballast tanks impacting the structural integrity of the vessel; and
- engine room explosion and loss of vessel stability.

Ship collisions were identified to be a major risk contributor to potential pollution from FPSOs. Shipping traffic routes and databases are needed for quantifying the collision risks from vessels navigating in the Gulf of Mexico. Development of collision avoidance procedures was found necessary. Further evaluation will include such measures as radar surveillance, a standby vessel, and installation of thrusters on the FPSO.

The operational plan for an FPSO in the Gulf of Mexico will depend on the manning philosophy that may differ from the conventional approach of evacuating platforms upon a hurricane warning in the region. Most deepwater leases will be farther away from shore and helibases. The personnel evacuation upon a hurricane warning will become more complicated with potential for higher risks than for the near shore sites. Several alternative safety systems, including maintaining platforms manned during hurricanes will be evaluated in Phase Two of the JIP. The turret mooring system that incorporates the risers and swivel is identified as a critical element. Further evaluation of the reliability and development of advanced design approaches are needed.

Other areas that require further study include escape and evacuation during process events and cargo storage, offloading and transportation operations.

Gathering data

Several participants have injected the results of their own studies into the JIP.

Certification agencies

- ABS provided a report on the current FPSO classification and approval requirements.
- BV performed offloading risk analysis.
- DNV provided an overview of the results from its past FPSO risk analysis studies.
- LRS provided a report on variables in the design of FPSOs and how to consider them.

FPSO contractors

- IHC Calland provided design and operations information to help in the QRA process. It also prepared a document summarising its experiences with various risk reduction measures proposed.
- MODEC performed a specific study on the greenwater impact on the FPSO hulls and design and operations information to help in the QRA process.
- Quantum Offshore Contractors (QOC) provided information from its worldwide database for flexible pipes and risers.

Oil companies

Chevron, Conoco, Marathon, Mobil, Pennzoil, Petrobras, Oryx, Statoil, Texaco and Williams Energy Services have provided:

- Conceptual details of an FPSO system and its PHA study.
- Experience from previous FPSO risk assessment.
- Other information and available databases.

Volume expansion of liquid fuels – A problem?

The problem of accounting is still with us and provides a continuing set of disputes between retailers and their suppliers. Should we leave the status quo? Should we provide stricter codes of practice? Should we legislate? The questions are clear but what is the best most economic answer to all parties?

All liquids expand and contract with temperature and this presents metering problems for those trading by volume in any liquid whose temperature can vary significantly as it passes along the supply chain. In the case with petrol, the fluid involved is highly volatile, environmentally damaging and sold on with very small profit margins. Thus the issue of temperature expansion losses at the supply point becomes highly contentious.

Apparent stock losses at filling stations can arise from many sources, principally measurement errors, vapour losses, leakage and thermal contraction. The problem has been addressed over many years but apparently without a satisfactory resolution.

NEL, acting on behalf of the National Weights and Measures Laboratory, has been seeking to identify the extent of the thermal contraction problem and then to identify what, if any, measures are needed to overcome the reported unfairness of trade. As part of the project NEL invites comments, opinions and evidence of constant losses due to temperature 'shrinkage' of fuels on delivery to filling stations or considerations of how equitable allowance for shrinkage can be accounted without an undue cost burden being added to the industry.

Any data, opinions or comments are more than welcome but, as time is short, a prompt response is necessary.

Technical information or submissions can be forwarded to:

NEL, Scottish Enterprise Technology Park, East Kilbride, Glasgow G75 0QU, UK; Fax +44 (0)1355 272536. FAO of either Mr Richard Paton Tel: +44(0)1355 272965
e-mail rpaton@nel.uk **or Mr Denis Boam Tel +44(0)1355 272 242**
e-mail dboam@nel.uk

The project will report findings to a seminar to be held at NWML on 11 March 1999. Attendance is by invitation and expressions of interest should be forwarded in writing or by fax to:

Ann Mohan, NWML, Stanton Avenue, Teddington, Middlesex TW11 0JZ, UK. Fax: +44 (0)181 943 7270

Portable soil analysis kit helps speed up site remediation

A new portable soil analysis kit for the on-site determination of total petroleum hydrocarbons across a wide range of soil types and petroleum products has been unveiled by Azur Environmental. The RemediAID patented test kit, developed in conjunction with Shell Research, is said to offer greater flexibility than existing portable systems and show a good correlation with standard infra-red test methods.

The system enables the user to run 10 tests concurrently, providing the potential to run 25 tests in one hour. It can also be calibrated to measure quantitative amounts of specific petroleum products such as leaded and unleaded gasoline and polyaromatic hydrocarbons (PAHs).

RemediAID is supplied with specially designed ampoules and pre-measured reagents, eliminating the need for pipetting skills or measuring flasks. Operator contact with reagents is kept to a minimum in order to improve safety.

The test is based upon the Friedel Crafts reaction, but with one fundamental difference, states the manufacturer: the intermediate remains in the solvent which allows the colorimetric analysis of the sample to take place. Other systems and methods rely on the comparison with a colour chart to give semi-quantitative results or the measurement of turbidity of the final solution. 'The use of a colorimetric end-point means RemediAID can be calibrated to determine various types of specific fractions, as well as allowing total petroleum hydrocarbons to be screened, where accuracy is not essential,' explains the company.

The testing system is also said to provide a quicker alternative to the standard laboratory method which is both costly and labour intensive, because only the contaminated samples need to be sent to the laboratory for confirmatory testing. This means that faster decisions can be taken during site investigations and site remediation. It also allows more samples to be analysed and processed in a set time to provide a more comprehensive site survey than would normally be possible.

Tel: +44 (0)1189 277000
Fax: +44 (0)1189 272842

Handy gas analysis

Dräger's new Ampliwarn Mini Beacon incorporates powerful visual and audible alarms to provide immediate warning of the presence of toxic or explosive gases. The portable system is designed for use with a number of personal gas detectors, including the company's Pac II and III, Pac Ex and Multiwarn I and II products. Up to four Ampliwarn units may be linked remotely to provide one master alarm unit covering a large area. The system can also be linked directly to the control room or to a remote sounder.

Tel: +44 (0)1670 352891
Fax: +44 (0)1670 356266

New player in analysis and synthesis

Shell is offering for the first time the expertise in chemical analysis and synthesis generated in its Oil Products business to customers outside the Group. Its laboratories in the UK, the Netherlands, Germany, France and Singapore will trade under the name Shell Global Solutions.

The company is also offering in-situ, in-field and on-line measurement technology, as well as statistical data analysis, mathematical modelling and a significant range of engineering and processing technologies. The company can also provide instruction courses for general laboratory skills through to advanced training on high-tech equipment.

A further new venture is the provision of an equipment calibration, preventative maintenance, troubleshooting and repair service.

Tel: +44 (0)151 373 5481
Fax: +44 (0)151 373 5654

Hydraulic power tong system improves rig safety

BJ Tubular Services has upgraded its Leadhand MK I hydraulic power tong system – which assists in the manoeuvring of hydraulic power tongs to and from the well centre line during casing and tubing operations – to further simplify installation and maximise lifting capacity efficiency.

The original system incorporates a hydraulically powered articulating arm, hydraulic power supply and remote control panel. The hydraulic power supply can be a self-contained unit or drawn from the existing rig supply. The arm is mounted in the derrick using brackets which allow the system to be rigged up or down in only 10 to 15 minutes. The remote control panel is located on the power tong and allows one operator to move the tong back and forth from the well. Leadhand MK II uses the existing rig's tugger line, requiring low levels of loading into the rig structure, to make installation a simple, straightforward procedure, states the company. Using the existing line is also said to greatly enhance the lifting capacity.

Both systems can be used with an integrated tong system to reduce the level of manual handling required and provide greater operator and rig crew safety, explains the company. The system's high level of stability is also said to provide safe control of the tong on semisubmersibles in rough sea conditions.

Tel: +44 (0)1224 249678
Fax: +44 (0)1224 249106

Reusable barrier coating cuts corrosion costs

Alocit Group claims that its Enviropeel thermo-plastic barrier coating can reduce the cost of corrosion on pipe flange joints by some 85% – a saving approaching $1mn on an average platform over a 20-year life.

The product is said to be environment friendly, re-usable, cost effective and simple to apply, and is capable of handling the most difficult crevice and bi-metallic corrosion problems associated with flange joints. The system is also claimed to be suited to the long-term protection of 'moth-balled' and stand-by machinery and components.

Enviropeel is applied by a specially designed spray system that heats the product before it is sprayed on to flange joints and their associated components. The product covers and seals the surface area before setting in seconds to form a solid protective barrier. It also penetrates deep into crevices, injecting powerful corrosion inhibitors to prevent the spread of existing damage and protect the steel from further attack.

The coating can be easily peeled away when access to a component is required and, being thermo-plastic, it can be returned to the spray unit for re-use when work is complete. The system's reusability also minimises stock holding, an important benefit on offshore installations where space is at a premium.

Protection of the newly exposed surface is maintained by a film of powerful corrosion inhibitors which is said to last for the life of the joint.

The barrier coating can be applied on almost any surface, including steel, concrete and wood, states the manufacturer.

Tel: +44 (0)1362 694915
Fax: +44 (0)1362 695350

Miniature ball valves offer space/weight saving

Parker Hannifin has extended its range of miniature instrumentation ball valves with 1/8- and 1/4-inch versions said to be capable of achieving up to 40% weight and space savings compared with conventional products. The new valves also feature a single-piece seat and packing component which is claimed to extend operating temperature range as well as eliminate leak paths and 'dead spaces' which can trap particles or build up deposits.

The new bi-directional MB2 and MB4 two- or three-port valves are available with a choice of three orifice sizes from 0.052–0.125 inches/1.3–3.2mm and flow coefficients from 0.03 to 0.15. They are rated for operation up to 172 bar.

Users can choose from 316 stainless steel or brass materials, in three-way or in-line two-way configurations, or angle two-way versions which eliminate the need for 90° elbows. The three-way version accepts the full inlet pressure rating on any port, extending application possibilities, states the company.

Tel: +44 (0)1271 313131
Fax: +44 (0)1271 373636

PC process control

Measurement Technology has developed a range of slim-line, ergonomic and lightweight touch-screen computers for monitoring and control of operations close to the process. Suitable for use in hazardous areas, the computers are said to be ideal for applications in chemicals and pharmaceuticals manufacturing, oil exploration, production and refining.

The MTL670 Series units are of flat panel, thin film transistor (TFT) design and offer the flexibility of boom-arm-, panel-, rack-, desk- or wall-mounting. Each model has an integrated touch-screen as the man–machine interface with TouchSurround™ which extends the touch sensitive area beyond the display and allows customisation. 'TouchSurround provides a much larger and more versatile interactive area which can be tailored to reflect customer applications with touchable pictures, symbols, icons, buttons and keypads,' explains the manufacturer. An extended version of the system can accommodate icon-intensive applications such as QWERTY keypads. Regular function keys can be programmed as short-cuts or replaced with graphics that match the user's applications software, providing increased functionality and ease of use.

The screens are said to be capable of withstanding severe abrasion, chemicals, shock and vibration, but remain responsive enough to be used with most types of work gloves.

PC specifications include Pentium® processors, with up to 128 MB RAM, Windows®95 or WindowsNT™ operating systems and 2.1 GB hard drives. Each model has onboard Ethernet™, two ISA expansion slots, two serial ports and one parallel port.

Tel: +44 (0)1582 723633
Fax: +44 (0)1582 422283

Respiratory protection

Designed to provide the wearer with maximum comfort and protection combined with the widest possible field of undistorted vision, the Vision 2 negative pressure filtering full facemask is the latest addition to Protector's respiratory protection range.

The facemask features a new visor shape and design which is said to offer almost unrestricted vision through its optically perfect polycarbonate visor, states the company. The visor is also specially hard-coated to provide solvent and impact resistance as well as radiant heat protection. A non-dermatitic liquid silicone rubber face-seal makes the mask feel very soft on the wearer's face. Correct fitting is provided by a full adjustable five-point head harness. The filters are positioned low on the mask – which weighs just 630 grammes – and close to the face in order to ensure good field of vision.

Two single filter models using standard 40mm diameter thread filters are available, together with an ultra-low profile twin filter version using filters from the Protector R60 half-mask range.

Tel: +44 (0)1695 50284
Fax: +44 (0)1695 50819

On-line petroleum analyser offers continuous checks

The new Phase Technology On-line Petroleum Analyser from Sartec can measure both freeze and cloud point using the same measurement technology as its ASTM approved laboratory analyser (see *Petroleum Review*, January 1999). The instrument can continuously sample the petroleum stream, with a programmable cycle time of three to 30 minutes, to produce the required ASTM test results.

The device is claimed to be easy to install and requires minimal maintenance. No chiller bath is required and residual wax is eliminated by the automatic warming of the sample at the end of the cycle. Each analyser is supplied with a sample conditioning and recovery system, ensuring a self-contained continuous operation.

On-line analysis of the petroleum stream improves process throughput, quality control and reduces wastage, states the company. Signal outputs can be fed into plant monitoring and alarm systems. Remote diagnostic checks can be undertaken via a modem link.

Tel: +44 (0)1732 884815
Fax: +44 (0)1732 885541

Foundation fieldbus certification

Fisher-Rosemount reports that its Analytical Oxymitter 4000 in-situ oxygen transmitter is the only flue gas oxygen analyser to have been authorised to bear the Foundation fieldbus registration checkmark. The checkmark provides assurance to those purchasing the 'plug and play' device that it will work with other Foundation fieldbus compliant hosts or registered field devices, regardless of manufacturer, without loss of functionality or integration.

The unit integrates an oxygen probe and field electronics into a single, compact package. The probe inserts directly into flue gas to measure oxygen. Advanced diagnostics include an on-line indication of the need to calibrate and 15 other alarms continuously available to the operator.

Tel: +44 (0)1243 863121
Fax: +44 (0)1243 845280

World-first for mobile drilling rig auditing

Aberdeen Drilling Consultants (ADC) has launched what it claims is the world's first software-based mobile offshore drilling rig audit management system. Developed in association with specialist software house PiSYS, the Technical Rig Audit Management System (TRAMS) assimilates information which previously could only be produced for offshore contractors and operators through an enlarged paper-based storage system, explains ADC.

Although several types of rig audits – including commissioning, pre-charter and in-situ – are covered by TRAMS, the core element is a three-tier checklist management system with sections, topics and detailed tasks allowing the user to identify problem areas. There are a total of 37 sections covering every working practice across the rig. TRAMS allows the user to access information specific to his/her requirements and also enables the storage of digital files associated with the audit such as video and still footage, scanned images and sounds.

TRAMS is said to list most offshore drilling units operating across the globe. The list enables users to compare the general capabilities with all rig audits previously carried out and provides the operator and rig auditors with the information required for evaluation purposes.

Tel: +44 (0)1224 209123
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thousands of repetitions in a limited period, it is necessary to develop a correlation between those uncertainties and the results of reservoir simulation studies. ●

Trevor Ridley would like to acknowledge the help and support given by BHP management in the preparation of this article

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NEW Publications

European Petrochemicals: The Battle for Global Competitiveness

Vasi Nadarajah (FT Energy, Maple House, 149 Tottenham Court Road, London W1P 9LL, UK). ISBN 1 85334 850 3. 168 pages. Price: £350.

This book explores the problems facing the European petrochemicals sector and discusses the positive action for the future using a combination of industry statistics and fresh data gathered from 16 major petrochemical companies in 22 European countries. It delves into the underlying nature of the major petrochemical producers, analyses their capacity and production, and pinpoints areas of potential development.

Engine Testing: Theory and Practice*

Michael Plint and Anthony Martyr (available from Customer Services Department, Heinemann Publishers Oxford, PO Box 382, Halley Court, Jordan Hill, Oxford OX2 8RU, UK). ISBN 0 7506 4021 9. 362 pages. Price (hardback): £40.

This publication aims to bring together the large and scattered body of information on the theory and practice of engine testing and test plant design. Now in its second edition, the book includes extended coverage of computer control and data logging of test procedures; water supply and treatment; combustion air, supply, treatment, effects on performance; drive shaft design; and exhaust emissions and legislation. It also incorporates a new section devoted to chassis dynamometers and test methods for complete vehicles.

The Economic Appraisal of Natural Gas Projects*

Willem J H Van Groenendaal (available from the Oxford Institute for Energy Studies, 57 Woodstock Road, Oxford OX2 6FA, UK). ISBN 0 19 730019 7. 248 pages. Price (hardback): £39.50.

Investment in the infrastructure for energy supply requires a detailed analysis of long-term demand for energy before crucial decisions are made – decisions which involve large financial commitments for projects with long lifetimes. The accuracy of the analysis can have a major influence not only on the future of a country's energy industry, but also on its economic health. The method used to support investment decisions in energy infrastructure is development project appraisal. This book aims to clarify a number of the methodological issues involved, illustrating the approach with the plans to develop an integrated gas transmission system in Java, Indonesia.

Industrial Emergencies and the Media – A Handbook for Survival

Philip Algar (FT Energy, Maple House, 149 Tottenham Court Road, London W1P 9LL, UK) ISBN 1 84083 037 9. 208 pages. Price: £395.

Any organisation, especially in hydrocarbons or shipping, can become involved in a crisis that attracts substantial media attention. How the media cover the emergency influences the company's future and could even prompt its demise. This handbook, written by Philip Algar, a regular contributor to *Petroleum Review* and a Member of IP Council, emphasises the commercial importance of positive links with the media and shows how to develop that relationship. Based on real incidents and hundreds of training sessions in many companies and countries, the report explains how to meet the media challenge. Specific information covers all aspects of response, helping the company to minimise damage to its reputation. Detailed advice covers, for example, organising a telephone response team, how to write a press release and undertaking successful press conferences and television interviews.

** Available on loan from the IP Library*

Latest from the Library

Temporary loss of access to back issues

During March 1999 the large storeroom at 61 New Cavendish Street is being fitted out with new shelving and rolling stacks. This work is much needed as the storeroom is currently filled to bursting point with useful back issues of periodicals and other historical publications.

However, this means that we will not have access to the material for two weeks. Therefore, if you wish to use the IP Library during March for research using material over one year old, please check with us before March so that we can ensure its availability. Telephone Liliana El-Minyawi on +44 (0)171 467 7113.

Library refurbishment – a reminder

During July and August of 1999 the IP Library at 61 New Cavendish Street will be refurbished. As a result, we will be temporarily closed to visitors – although you will still be able to contact us by post, telephone, fax and e-mail.

Contact details

- Information queries to:
  Chris Baker, Senior Information Officer, +44 (0)171 467 7114
  Sue Tse, Information Officer, +44 (0)171 467 7115
- Library holdings and loans queries to:
  Liliana El-Minyawi, LIS Assistant, +44 (0)171 467 7113
- Careers and educational literature queries to:
  Octavia Leigh, Information Assistant, +44 (0)171 467 7116
- Web page queries to:
  Catherine Pope, Webmaster, +44 (0)171 467 7112
- LIS management queries to:
  Catherine Cosgrove, Head of LIS, +44 (0)171 467 7111

Fax any of us on +44 (0)171 255 1472 or e-mail us on **lis@petroleum.co.uk** Visit our web site at **www.petroleum.co.uk**

UK Register of Expert Witnesses

Are you an expert witness wishing to increase your rate of instruction? If so, you could have your details included in the 12th edition of *UK Register of Expert Witnesses* which is currently being compiled.

Seen by litigation lawyers in the top 3,000 practices in the UK, this 'live' database currently holds the details of more than 3,000 vetted, experienced expert witnesses whose fields of expertise range from accountancy to yacht building, anaesthesia to zoology, and acupuncture to zinc. The subject index runs to no fewer than 17,000 entries. The database is available in three formats:

- as a book (distributed free of charge to the top 3,000 UK solicitor firms),
- as a Windows-compatible software, and
- on-line at **www.jspubs.com**

Readers of *Petroleum Review* who wish to make known their availability as expert witnesses to a wider circle of the legal profession should contact Kate Porter at J S Publications, PO Box 505, Newmarket, Suffolk CB8 7TF, UK. Tel: +44 (0)1638 561590 Fax: +44 (0)1638 560924.

ISO TC 67 New Year Resolutions

TC 67 show once again that they are ahead of the game, this time in relation to resolutions. Most of us made ours whilst enjoying the hospitality of landlords around New Year. TC 67 made theirs back in September, during their 18th Plenary Meeting. While most of us are contemplating a year without fried food, cigarettes or alcohol, TC 67 face the challenge of publishing 20 standards. The question many people are asking of their resolutions by now is whether they are achievable. The background to most resolutions ensures they are at best 'stretch targets' and I suspect this question has been answered by many already! However, TC 67 must achieve theirs or the vital industry support will be lost. It is fortunate that excellent technical progress was made on many standards during 1998. There is a risk that the current pressures on industry will reduce the number of technical volunteers that make standardization happen. What is required now is a final push and we are therefore soliciting further support. The target to publish 20 standards in 1999 and a further 30 in 2000 is certainly ambitious.

One way to help achieve this is to increase the efficient use of technical experts' time. We are therefore reorganising the subcommittee structure under PSE/17. Subcommittee meetings will become a thing of the past. All of the time spent by technical experts in the UK on standardization will be channelled into developing the International Standards in their particular area of interest. This will be achieved through the continued evolution of the Review Network.

ISO/TC 67
Mission: To create value added standards for the oil and natural gas industry
Vision: Global standards used locally worldwide

Why am I not on a Review Network?

If you have not yet heard of the Review Network concept for getting involved in the drafting of standards for the E&P side of the business (the work of TC 67) it can only be assumed that your 1997 copies of *Petroleum Review* were either used by the postman as extra padding for his bicycle seat or swiped by your dog each month. The concept is simple. Having the time to attend BSI meetings and offer your technical expertise for the benefit of standardization (and the industry) is a luxury few can now afford. However, it is possible to be put on a mailing list for a particular standard of relevance to your technical interest, and receive a copy when it is distributed for comment. One lunch hour later (don't forget the legal requirement to have a break at lunchtime!) your technical comments can be forwarded for the consideration of the Lead UK Expert for the standard. For a complete list of the TC 67 standards currently under preparation, visit the TC 67 website at **www.api.org/iso/tc67** If you can offer technical expertise on any of the subjects listed, please contact Sjoerd Schuyleman (+44 (0)171 467 7132) or Martin Hunnybun (+44 (0)171 467 7133) today.

Our website can be found at: www.petroleum.co.uk

IP THE INSTITUTE OF PETROLEUM

Call for papers

The Future Role for Aromatics in Refining and Petrochemistry

13–15 October 1999, Erlangen, Germany

Continuing the series of joint events between AFTP, DGMK and the IP, DGMK plans a conference for petroleum refiners, experts from the chemical industry and research institutions to discuss the future role of aromatics in gasoline in response to the expected requirements of the auto oil programme, including the wider repercussions for refining and petrochemicals. The conference will also cover improved and novel catalytic pathways for the conversion of aromatics into valuable products and separation techniques for aromatics. Particularly welcome topics would be:

- The future design and operation of catalytic reformers.
- Novel and improved catalytic conversion of aromatics into high value chemicals.
- Shape-selective catalysis with aromatics.
- Removal of aromatics by extraction, adsorption or related processes.

Contributions are now being solicited for oral and poster presentations. Proposals should contain the title of the paper to be submitted, the author(s) names and affiliation(s) including their telephone and fax numbers and if possible, e-mail addresses, followed by a concise abstract. The deadline for proposals is **31 March 1999** and they should be sent to:

DGMK, Attention Dr G Tessmer, PO Box 600549,
D-22205 Hamburg, Germany.
Tel: +49 40 63900412
Fax:+49 40 6300736
e-mail: dgmk@online.de
or contact John Evans at the IP for more information.

www.petroleum.co.uk

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Details: Pauline Ashby, The Institute of Petroleum

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Details: Center for Professional Advancement, The Netherlands
Tel: +31 20 638 28 06
Fax: +31 20 620 21 36

16 February
London: *Knowledge Management Workshop*
Details: Pauline Ashby, The Institute of Petroleum

16 February
London: *IP Annual Luncheon*
Details: Pauline Ashby, The Institute of Petroleum

17 February
London: *The 12th Oil Price Seminar and Exhibition on Crude Oil Pricing in Deregulated Markets in Asia*
Details: Pauline Ashby, The Institute of Petroleum

18 February
London: *International Conference on The Caspian Region: The Major Oil and Gas Play for the Next Decade.*
Details: Pauline Ashby, The Institute of Petroleum

16–17 **London**
Health Effects of Vehicle Emissions
Details: Energy Logistics International, UK
Tel: +44 (0)1628 671717
Fax: +44 (0)1628 671720

18–19 **London**
ICIS-LOR World Base Oils Conference
Details: George Lowrie, ICIS-LOR, UK
Fax: +44 (0)181 652 3929
e-mail: george.lowrie@icislor/com

20–23 **Bahrain**
MEOS 99
Details: The Society of Petroleum Engineers, UK
Tel: +44 (0) 171 487 4250
Fax: +44 (0) 171 487 4229

22–23 **Aberdeen**
Best Practice Compliance with Environmental Regulations for Offshore Drilling
Details: Anita Bath, IIR Ltd, UK
Tel: +44 (0)171 915 5032
Fax: +44 (0)171 915 5000

22–23 **Aberdeen**
Field Applications & New Technologies for Multiphase Metering
Details: Penny Richards, IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858

23–24 **London**
Designing and Implementing an Effective Crisis Management Strategy
Details: Learning in Business, UK
Tel: +44 (0)181 944 4300
Fax: +44 (0)181 944 4311

25–26 **Sydney**
Australasian Energy Players
Details: Global Pacific & Partners, Australia
Tel: +61 2 9460 6771
Fax: +61 2 9460 6778
e-mail: glopac@ozemail.com.au

25–26 **Amsterdam**
Offshore Pipeline Technology 22nd Event
Details: IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e-mail: cust.serv@ibcuk.co.uk

27–28 **Tehran**
The IR of Iran Petrochemical Investment Forum
Details: Middle East Infrastructure Development Congress, Dubai
Tel: +971 4 314552
Fax: +971 4 318710

MARCH

1–2 **Singapore**
3rd Annual Asia Upstream
Details: Global Pacific & Partners, Australia
Tel: +61 2 9460 6771
Fax: +61 2 9460 6778

1–2 **New York**
Oil and Gas Investments in Re-Emerging Middle East Markets: Iran & Iraq
Details: CWC Associates, UK
Tel: +44 (0)171 704 6161
Fax: +44 (0)171 704 8440

1–4 **London**
Angola Energy Summit
Details: IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858

3–4 **Miami**
Oil and Gas in Latin America: The New Era
Details: CWC Associates,UK
Tel: +44 (0)171 704 6161
Fax: +44 (0)171 704 8440

4–5 March
Aberdeen: *Reusing or Recycling Offshore Facilities?*
Details: Gillian Stephenson, University of Aberdeen
Tel: +44 (0)1224 272431
Fax: +44 (0)1224 272079

5 **Miami**
Deep Water: Investment Opportunities in Latin America
Details: CWC Associates, UK
Tel: +44 (0)171 704 6161
Fax: +44 (0)171 704 8440

10 **Aberdeen**
Survival Plus 1999: Crine Network Annual Conference
Details: Sally Ann Melia, Crine Network UK
Tel: +44 (0)171 593 2330
Fax: +44 (0)171 593 2323

14–17 **Qatar**
3rd Doha International Oil & Gas Exhibition
Details: The Middle East Association, UK
Tel: +44 (0)1564 784999
Fax: +44 (0)1564 784499

15–17 **Oman**
Improved Measurements of Bulk Liquids
Details: Abacus International, UK
Tel: +44 (0)1245 328340
Fax: +44 (0)1245 323429

Membership News

NEW MEMBERS

Mr W Abdmessih, Oiltest Inc
Mr P Ahmed, Sidcup
Mr I A N Anadi, London
Mr D M Arnold, Goldhanger
Mr J Bailey, Sunningdale
Mr T Baudwin, Greig Middleton & Co Limited
Mr C Bhima, Mobil Gas Marketing
Mr S M Bickers, Stafford
Mr A E Boatwright, London
Mr S F Boocock, Middlesex
Mrs D J Booth, Hydrosearch Associates Limited
Mr K A Bower, Hemel Hempstead
Mr S Boyle, The Royal Bank of Scotland
Mr D A Bulmer, David Bulmer & Associates
Mr M H Butani, Arthur Andersen & Company
Miss N Cajigas, Greenwich Natwest
Mr T J Calver, State of Qatar
Mr C A R Camargo, Brazil
Ms G Carroll, Arthur Andersen
Mr G Chaudhri, Arthur Andersen & Company
Mr B A Cork, BA Consulting (1987) Limited
Mr M Cripps, Transearch Cripps Sears
Mr M J Curtis, London
Mr J O Dalton, West Aldie
Mr N W Danton, Widecontact Limited
Mr M R Davies, Portsmouth
Mr A G de Azevedo, Brazil
Mr J de Saugy, Berger Recordon de Saugy
Mr C Drage, PGS Reservoir (UK) Limited
Mr S Elliott, Westsonic Limited
Mr P F Fennelly, Tring
Mr G R Fisher, The Perch Garage
Mr C S Galbraith, TDG Nexus
Mr R Hagan, RPC Consultancy Limited
Miss M E Hall, Norton Rose
Dr B Hamilton, Esso UK plc
Mr P B Heimann, Zurich Global Energy
Miss S Hitchcock, Arthur Andersen
Mr N-H Hur, Ssangyong Oil Refining Co Limited
Mr P W Hurley, X-Ray Analysis
Mr J R Kearey, Kidlington
Mr J A Kershaw, Harrogate
Mr C Killeen, Oiltest Inc
Mr S A King, King & Co
Mr D N Kye, Korea National Oil Corporation
Mr O Lawal, Aberdeen
Ms E G Logan, London
Mr K W Luk, Occa International Limited
Mr S Mannan, Arthur Andersen
Mr P B Martin, Mobil Oil Corp
Mr D Mavromichalos, Cyprus
Ms E A Miller, London
Mr A J Morgan, PriceWaterhouseCoopers
Mr N N Nayar, Baron Associates
Prince C C Okirie, London
Mr D Pattison, Stockton-on-Tees
Mr J S Richmond, JSJ Installations
Mr M Ricks, Michael Ricks & Associates
Mr M Salter, Abbot Group plc
Mr S D Q Saud, East Africa Grains Limited
Mr E E Smith, PSG International Limited
Mr D Smitherman, Heathrow Refuelling Service Co Limited
Mr I G Spencer, Rigblast Energy Services Limited
Mr S J Stone, Lubrication Services (UK) Limited
Mr M J Sutherland, SFF Services Limited
Mr R Tan, Hong Kong
Mr J Temple, Tadworth
Mr R Vasanthkumar, USA
Mr A Verdin, Barclays Bank plc
Mr N J Walker, Sandbach
Mr M Waller, Oiltest Inc
Mr S P Williams, Southwater

NEW STUDENTS

Mr D G Borgohain, India
Mr R A Carter, Middlesbrough
Miss J A N E Demetriadi, Wantage
Mr S Dessanay, Centre for Petroleum Studies
Mr S Ghani, Wolverhampton
Mr P J Jacobsen, Denmark
Mr S Kocharunchitt, Birmingham
Mr S W Loth, London
Mr S S Ojah-Maharaj, Edgware
Mr A B Osho, Nigeria
Mr N J Pink, Centre for Petroleum Studies
Mr A M Raja, Rochdale
Mr S Spiris, Liverpool
Mr B Zakirov, London

STUDENT PRIZEWINNER

Mr A P Chesters, Bagshot

NEW CORPORATES

Oracle Corporation UK Ltd, 50 Oracle Parkway, Thames Valley Park, Reading, Berkshire RG6 1RA, UK.
Tel: +44 (0)118 924 0000 Fax: +44 (0)118 924 3881

Representative: Ms Heather Oshin
Oracle Corporation UK Ltd is the world's leading supplier of software for information management and the world's second largest software company with annual sales of $7.6bn. The company offers its database, tools and application products, along with the related consulting, education and support services, in more than 140 companies around the world. Oracle offers information management solutions for the upstream and downstream sectors.

Oil Recruitment Ltd, Regent House, Bexton Lane, Knutsford, Cheshire WA16 9AB, UK.
Tel: +44 (0)1565 654830 Fax: +44 (0)1565 755607
e-mail: mail@oilrecruitment.co.uk

Representative: Mr Nick Smith, Director
The Oil Recruitment Agency is dedicated to the downstream oil industry. Oil Recruitment handles senior management, middle management and technical roles in petroleum distribution, marketing, retailing, refining, storage, inspection, trading and broking. Although only recently formed, the company already has an extensive database of experienced individuals seeking challenging positions in the industry.

IPIECA, 2nd Floor, Monmouth House, 87–93 Westbourne Grove, London W2 4UL, UK.
Tel: +44 (0)171 221 2020 Fax: +44 (0)171 229 4948

Representative: Mr Michael Boeuf, General Secretary
IPIECA is involved in global and international environmental and health issues related to the petroleum industry, including global climate change, oil spill management and response, urban air quality management and emerging issues, biodiversity and agenda 21. IPIECA's programme takes full account of international developments in these global issues including those developments within the UN and within intergovernment institutions and industry groups.

IP Conferences and Exhibitions

IP Week 1999: London 15–18 February

See inside front cover for more details.

Places are limited and participants are advised to register early.

The IP Week 1999 Programme of Events which includes the programme and registration form is now available.

IP International Seminar

The Institute of Petroleum will again organise its European Retail Conference and specialist half-day Seminar in association with the 'Forecourt International and the Convenience Retailing Shows' at the NEC in Birmingham from 9–11 March. These events have rapidly become a well established forum for the discussion of current issues affecting retailing in the UK, continental Europe and the new rapidly developing markets to the East, and attract a high calibre audience of delegates and exhibitors from the UK, Europe and overseas.

The New Consumers – Growing Petrol Retail Markets in Russia, Central and Eastern Europe

NEC, Birmingham: 9 March

Organised in association with the dti Department of Trade and Industry

Irrespective of temporary setbacks in some markets, the countries of Central and Eastern Europe provide significant growth opportunities for private vehicles and the provision of petroleum products to fuel them. This Seminar will look at the development of petrol and associated retailing and the scope for supplies of retail equipment, goods and services across the region.

The IP European Retail Conference
The Profitable Forecourt

NEC, Birmingham: 10 March

This event will address the different strategies being adopted by major oil companies and other diverse players in the market to restore a sustainable level of profit from their European retail operations.

Organised in association with

FORECOURT International

The Convenience Retailing Show 9-11 March 1999, NEC Birmingham

The programme and registration forms are now available

1999 Training Courses

The 1999 Training programme includes the following Courses:

Training Course on Trading Oil on the International Markets
Cambridge: 26–30 April

Training Course on Price Risk Management in the Oil Industry
Cambridge: 24–28 May

Training Course on Operations Practice in Supply Trading
7–11 June

Training Course on Introduction to Oil Industry Operations
London: 16–18 June

Training Course on Introduction to Petroleum Economics
London: 21–23 June

The Institute of Petroleum is widely acknowledged within the oil and gas industry as the leading provider of introduction courses to the whole range of oil industry operations and economics.

The complete 1999 Programme of Training Courses is now available.

International Conference on
Offshore Marine Support (OMS '99)
Southampton: 12–13 October

The programme and registration form will be available in April.

Programmes and registration forms for the above events are available from:

Pauline Ashby, Conference Administrator, Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR, UK

Tel: +44 (0)171 467 7100
Fax: +44 (0)171 255 1472

e-mail: pashby@petroleum.co.uk

or view the IP web page: www.petroleum.co.uk

IP Discussion Groups & Events

The Institute of Petroleum Discussion Groups have been combined to form

The IP Discussion Group: Energy, Economics, Environment

London Branch

'Exploration of the East Sakhalin Shelf'

Tuesday 16 February 1999, 17.30

Paul Nixon, Sakhalin Project Manager (G&G) Vice-President, Texaco Exploration Sakhalin Inc

Tea and biscuits will be served at 17.15. Light refreshments will be available afterwards.

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

Energy, Economics, Environment

'Gas in Britain and Europe: Deregulation? A Single Gas Market? – The Impact of the Interconnector'

Tuesday 9 March 1999, 17.00 for 17.30

Ian Thomson, Oakwood Consultants

IP Contact: Jenny Sandrock

Energy, Economics, Environment

Transport in London'

Monday 2 March 1999, 12.00 for 12.30 until 14.15

Jeffrey Archer, potentially candidate for Mayor of London

This meeting includes a buffet lunch at a cost of £18. Prior registration is essential. Application forms will be mailed to Discussion Group members in February; non-members please apply for a form.

IP Contact: Jenny Sandrock

Midlands Branch

'Urban Transport for the Millennium'

Wednesday 21 April 1999, Austin Court Birmingham

The increasing emphasis on the conflicts of urban transport, not only in the UK but across Europe and the world, makes this Seminar an important and timely event. Those with an interest in transport and the health problems in an urban environment will find the papers on these subjects fascinating. The eminent speakers giving papers at the Seminar are all professionals, at the forefront of knowledge and expertise in their fields. Knowledge gained from the Seminar will enable those with strategic responsibilities to formulate future plans.

In particular the Seminar will discuss the real alternatives for other fuels, and will show what the petroleum industry is doing to safeguard the environment, and at the same time provide the energy needed for transportation.

The following papers will be included:

- Health effects of air pollution
- Urban pollution from urban transport
- Alternative transport fuels for the future
- Balancing the motor vehicle equation
- How green is my oil company?
- Birmingham City Council overall policy visions

The cost of the Seminar will be £20 per person, including lunch.

The Seminar is being organised in association with Birmingham City Council and Elf Oil UK Ltd.

In conjunction with this important Seminar the Institute of Petroleum, Midlands Branch, is awarding two student prizes for the best papers submitted on the question of urban transport. The students will be studying at a Midlands Educational establishment.
One prize will be given to a student aged 16 to 18 years.
The second prize will be awarded to an undergraduate at a Midlands university
Each prize is worth £150 to the student and a further £150 to the educational establishment where the student is studying.

For further information on the Seminar, please contact

W M Ward C.Eng, BSc, MInstE, FInstPet.
The Rodgelands, Bank Lane, Abberley, Worcester, Worcestershire, UK. WR6 6BQ
Tel: +44 (0)1299 896654 Fax: +44 (0)1299 896955
e-mail: wm_ward@msn.com

For a complete and up-to-date listing of all IP Events see our website: www.petroleum.co.uk

MOVES People

Bob Connon, Managing Director of Chevron UK Ltd, has been elected President of the UK Offshore Operators Association (UKOOA) for the forthcoming year. The Association's Executive Officers for 1999 are: Vice-President, Francis Gugen (Managing Director, Amerada Hess); Vice-President, Mark Hope (Technical Director, Enterprise Oil); Honorary Secretary, Pierre Godec (Managing Director, Elf Exploration UK); and Honorary Treasurer, Alan Jones (Director and General Manager, BP Exploration Operating Company).

David C Codd is the new Managing Director of Texaco Ltd, and Director of New Business Development for Europe, Africa and the Caspian region for Texaco's worldwide upstream. He is also Director and Chief Legal Advisor for Texaco Ltd in the UK. Based in London, Codd will continue to oversee legal affairs in the London office.

As part of the merger between TOTAL and Petrofina, **Albert Frère**, **Paul Desmarais,** and **Thierry de Rudder** have been appointed Directors.

Royal Dutch/Shell has appointed Chief Executive Officers to run its Oil Products and Exploration and Production units. **Paul Skinner** is now Chief Executive in Oil Products. **Steve Miller** remains the Chairman of Oil Products and Group Managing Director. **Phil Watts** will be acting Chief Executive of Exploration and Production, as well as continuing as Chairman of the EP Business and Group Managing Director.

Former Energy Minister, **Lord Fraser of Carmyllie**, has been appointed as the new Chairman of the International Petroleum Exchange (IPE). He takes over from **Richard Reinert** of Refco Overseas, whose three-year term is expiring. Lord Fraser resigned from his post as Conservative Deputy Party Leader in December 1998.

Lasmo's new senior management team includes: **Joe Darby,** Chief Executive Officer; **Chris Wright**, Group Managing Director; and **Paul Murray,** Group Finance Director. **John Hogan** and **Dick Smernoff,** while relinquishing their executive roles, will remain as Directors of the company until the next Annual General Meeting in April.

Opec has elected **HE Dr Youcef Yousfi**, Minister of Energy & Mines of Algeria and Head of its Delegation, as its President. Minister of Energy & Industry of Qatar and Head of its Delegation **HE Abdullah bin Hamad Al-Attiyah**, has been elected Alternate President. **Ali A Fituri**, Governor for the Socialist Peoples Libyan Arab Jamahiriya, has been appointed Chairman of the Board of Governors for 1999, and **Dr Aboki Zhawa,** Governor for Nigeria, Alternate Chairman.

Boris Jordan has joined Sidanco as the company's new Chairman. He was formerly with MFK-Renaissance, linked to Oneximbank, majority shareholder of Sidanco.

Stuart Howell MInstPet has been appointed Retail Course Director at The College of Petroleum and Energy Studies based in Oxford. Howell was former Head of BP's retail business in the UK.

Martin Maeso (above) has joined the Institute of Petroleum in the new position of Environment Manager. He was formerly with the Automobile Association where he was Head of Environmental Policy. In his new role at the IP, together with Technical Officer _Alia Alavi_ (below), Maeso will support and advise on all environmental aspects of the Institute's work programme. _John Phipps_, who previously supported the Institute's environmental programme, will now focus on Test Methods, Measurement, Standards, and Microbiological projects.

Frank A Risch is the new Vice-President and Treasurer of Exxon Corporation. He succeeds **Edgar A Robinson** who has retired after 38 years of service. Risch joined Exxon in 1966 and his most recent position was as Assistant Treasurer of Exxon Corporation. **Daniel S Sanders** succeeds **Ray B Nesbitt,** who is retiring as President of Exxon Chemical Company. He has also been elected as a Vice-President of the Corporation by the Board of Directors. Sanders was formerly Vice-President of Exxon Chemical Company. He joined the company in 1961.

Scottish Enterprise Energy Group has appointed _Liz Mallinson_ as its new Operations Manager and Deputy to its Head of Energy. Mallinson rejoins the Energy Group from a three-year secondment with Scottish Development Finance, the venture capital arm of Scottish Enterprise with whom she previously spent seven years in various management positions in the oil and gas, business and environmental teams.

Eric Turner has been appointed Director of global consultants Arthur D Little's Environment, Safety and Risk group in Brussels. His previous experience includes business development and consulting across Europe and Asia-Pacific. In his new role he will be working with clients on the component parts of sustainable development.

Two new members have been appointed to the Board of the Environment Agency. **Professor Richard Macrory** and **Alan (AJP) Dalton** joined the Board on 1 January. Both appointments are for a period of three years.

Gorm Gundersen is the new Executive Vice-President and Member of the ABB Group Executive Committee, in charge of the oil, gas and petrochemicals segment. Previous positions include Head of ABB's global oil, gas and petrochemicals business area, based in Norway, and Deputy Manager of the business area from 1995.

Minale Tattersfield Design Strategy

International Design Consultants for the Energy Sector

OFFICES IN: LONDON, PARIS, MILAN, ZÜRICH, PRAGUE, CASABLANCA, KUWAIT, JEDDAH, U.A.E., KUALA LUMPUR, HONG KONG, OSAKA, TOKYO, BRISBANE, SYDNEY, BUENOS AIRES, RIO DE JANEIRO.

▲ Petrol station design for IP, Italy

▼ Prototype of totem sign for IP

▼ Canopy and totem detail for IP, Italy

Minale Tattersfield has 35 years' experience in petrol station design and has worked internationally for companies including BP, Agip, IP, YPF, Total, Afriquia, Elinoil, Thai Oil, Hydro and Texaco, among others.

In the area of transport design, we have also completed major projects for London Transport, BAA, and Eurostar train.

Speed is essential in the redesign and refurbishment of petrol stations to minimise loss of revenue, however consulting and coordinating specialist design consultancies for each individual area can be time consuming.

▲ Corporate identity for Elinoil, Greece

Minale Tattersfield offers a one stop service, with the experience and expertise to manage your complete project efficiently, from initial concepts through to final completion.

We have specialist skills needed for each area of the complex process of petrol station design.

- Graphic design for brand identity and signage,
- Architectural / urban design for the building, canopy, and surrounding landscape,
- Industrial design for petrol pump, car wash, lube bay, self-standing structure,
- Packaging design for lube products,
- Retail design for convenience store.

▲ Corporate identity and livery for Eurostar

▼ Hammersmith tube station

▲ Packaging for BP

▼ Interior of Heathrow Express

▲ Proposal for Heathrow Express

▼ Identity for IP's self-service stations

▲ YPF Petrol station contract with Minale, Tattersfield, Piaton & Partners

▲ Livery for Elinoil, Greece

▲ Petrol station design for Elinoil, Greece

▼ Mintat petrol station designed for Agip

mintat *for AGIP*

TRANSPORTABLE PETROL STATION

The Mintat (AGIP) petrol station is ideal for areas where environmental constraints restrict the building of permanent stations. Costing considerably less than a permanent petrol station, it is well suited to sparsely populated rural areas in developing countries. It can be used to reduce loss of revenue during the refurbishment of station networks and accommodate the seasonal flow of traffic in tourist areas and at large sporting events.

A transportable, fully autonomous petrol station, built on a modular, container based system of inter-connectable units which can be installed and fully operational in 48 hours. It complies with the latest environmental legislation including a vapour recovery system during discharging and filling and guarantees maximum operating safety. The tanks have a capacity of between 22,000 and 44,000 litres to distribute two types of petrol and diesel if required.

The standard modules of the transportable service station are composed of:

- *Tank Section*
  Size 2.4z
- *Office Section*
  Size 2.40 x 9.20 x H 3.30 m.
- *Canopy*
  Size 9 x 3.60 x 1.3 m.
- *Service Ramps*
  Size 14 x 3.2 x 0.3 m.
- *Set of External Trimmings*
  Outer fascia, modular cladding panels, tubular protection, outside illumination.
- *Utilities Plants*
  Electrical plant and earthing system, lighting plant, fire fighting system, heating plant, fuel dispenser and control system.
- *Signs*
  Two illuminated signs with trademark and company logo, two signs on the fascia, one pricing panel.
- *Furnishings and Accessories*
  Internal furnishings, shelves, W.C. service.

- *The MINTAT MARK II,* incorporating a four hour fire rated tank assembly meeting SWRI 95-03 & 93-01, UFC Standard A-11-F-1 (79-7) and NFPA 30 & NFPA 30A is in the final stages of development.

Your company livery can be applied as illustrated below.

For further details, contact:

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The Courtyard,
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Surrey, TW9 1AJ,
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