Petroleum review

APRIL 1998

Latin America – roundup
Booming demand, production and reserves

North America – gas supply
Closer integration on market liberalisation

Offshore technology
Multiphase pumps to boost subsea wells

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

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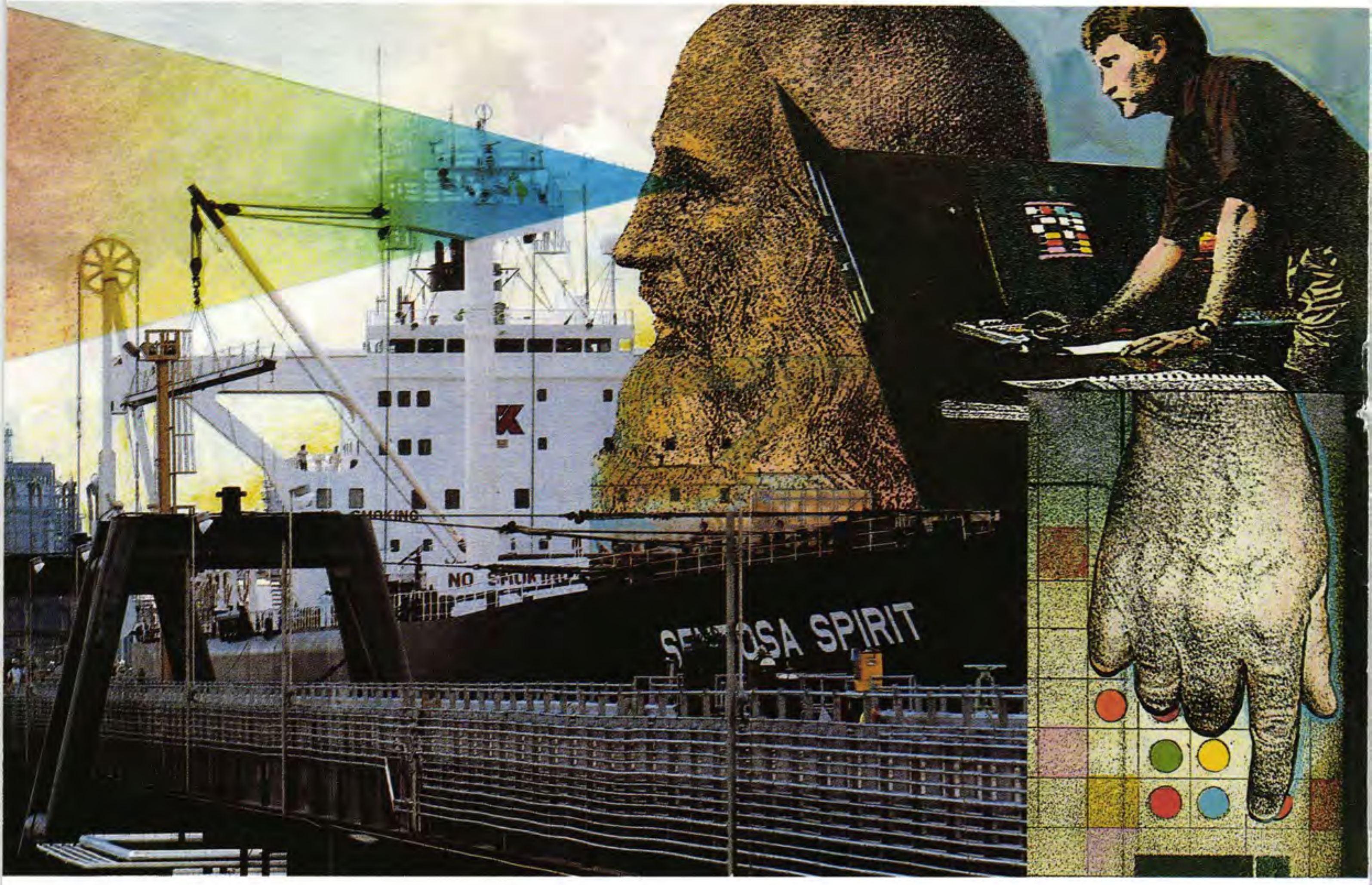
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Petroleum review

APRIL 1998 VOLUME 52 NUMBER 615

£8.75 • SUBSCRIPTIONS (INLAND) £105.00 (OVERSEAS) £115.00

PUBLISHER

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A charitable company limited by guarantee

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SUBSCRIPTIONS

Subscription Enquiries: Portland Press

Tel: +44 (0)1206 796351 Fax: +44 (0)1206 799331

Printed by The Thanet Press Ltd, Margate

US MAIL: *Petroleum Review* (ISSN 0020-3076 USPS 006997) is published monthly by the Institute of Petroleum and is available Periodical Postage Paid at Middlesex, New Jersey.

Postmaster: send address changes to *Petroleum Review* c/o PO Box 177, Middlesex, New Jersey 08846, USA.

ABC BUSINESS PRESS

ISSN 0020-3076

MEMBER OF THE AUDIT BUREAU OF CIRCULATIONS

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: Bachaquero tank farm, Venezuela

Photo: Petroleos de Venezuela SA

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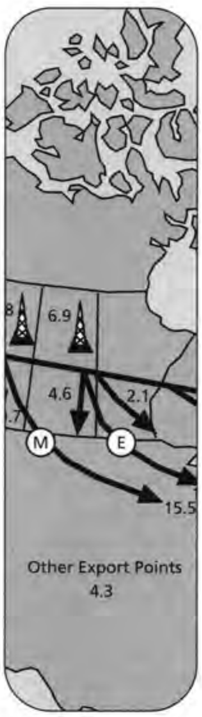

FEATURES

REGULARS

ROUNDUP From the Editor

Sending the wrong signals

There seems little doubt, with spot Brent prices hovering a little over \$12/barrel, stocks rising rapidly and the latest estimates that lack of Far East demand could reduce 1998 oil demand growth by 500,000 b/d, that the industry is facing a crisis.

Futures markets, however, appear to be providing a perverse incentive to further overproduction. At the moment prices for May and June delivery are \$1.50/barrel above spot Brent levels. This gives producers the ability to produce yet more crude and sell forward to lock in a price.

The futures market appears to be betting that 'something will turn up' to strengthen oil prices. The danger is that if nothing does, the industry will end up with excess stocks, excess production and prices heading for levels it does not bear thinking about.

So what might 'turn up'? In terms of production being shut-in, because it is uneconomic, the answer is not very much. Some Canadian heavy oil production has already been shut-in, some US stripper well production will cease if equipment breaks or requires expensive maintenance. A range of higher cost new projects are likely to be cancelled or delayed, but, in terms of current production, prices would have to move to \$5/barrel before there was any significant shut-in. The \$5/barrel level is the probable marginal cost of deep-water offshore production in the North Sea, Gulf of Mexico, Brazil and Gulf of Guinea.

What the market believes or thinks it knows is that Opec will cut production to firm prices. This, however, is to attribute more power and cohesion to Opec than there is any evidence for. While all members know a major cutback would strengthen prices they do not wish to give a free ride and cede market share to those who do not cut back. In any case most Opec governments lack the financial reserves to last out even a short-term reduction in production. Most would see survival of the government as the overriding priority. However, in present conditions even a fudged compromise over cutbacks would be seized on and would probably be enough to stabilise prices.

One of the major problems, particularly in Europe, is that government tax take on oil products is so high that it is virtually impossible for the companies to stimulate demand by cutting prices. This produces the perverse situation where there are strong incentives to increase production but little ability to stimulate demand for it. In the UK the government has just raised fuel duties and threatened to raise North Sea taxation. It is difficult to think of a worse combination for companies operating in the UK. We may all be about to find out, the hard way, how real is the UK sector operators' threat to cancel 80% of new North Sea projects.

Flurry on the forecourts

We appear to have caused something of a flurry with our *1998 Retail Marketing Survey* in that the total number of forecourts in operation rose to a new total of 14,284. For those who did not read the accompanying editorial, the explanation is that we managed to identify 871 small, usually single-pump stations in remote locations, that had managed to slip through all previous surveys. These, however, are the very tail of the forecourt market and account for only very limited throughput. On a like for like basis, 795 forecourts closed in 1997 roughly half the 1,496 closures seen in 1996. While this hardly represents a return to forecourt prosperity it does suggest that the worst of the cutbacks are probably over.

As the industry has always found our survey useful we have tried to extend and expand it. This year we introduced data about forecourt shops for the first time and next year we will expand this further.

Another innovation for 1999 will be to get the total number of nozzles operated by each company. This will give a rather clearer picture of who operates the larger forecourts and whose operations are confined to single-pump sites. We look forward to receiving full cooperation from the industry in making our survey as useful and comprehensive as possible.

Meanwhile, we apologise to anyone who was misled into thinking 1997 a closure-free year.

Fighting back

For far too long the oil industry has failed to defend its corner, allowing its critics a spurious plausibility. It is therefore very pleasing that UKOOA, on behalf of its members, is starting an advertising campaign in Scotland (see p4) to improve the image of North Sea oil by demonstrating how it affects the lives of everyone and the gains derived from it.

Mark Moody-Stuart in his lunchtime address during IP Week drew attention to the benefits oil and gas bring in terms of standards of living and providing opportunities for the many previously only open to the richest few.

Too many people have become bogged down, even obsessed, with the problems (real enough) and have forgotten the benefits. The UKOOA campaign is a small step towards redressing the balance.

Web World

The Internet site **www.northseaoil.co.uk** is the website backing and extending UKOOA's campaign for a greater recognition of the benefits of North Sea oil. The site features details of the campaign, impact on the environment, economy, a map, fact sheets and the opportunity to make comments and suggestions. The site, like so many others, is hot-linked from the Institute of Petroleum site **www.petroleum.co.uk**

All this year the people involved with the IP site have been working hard to make it as comprehensive and user-friendly as possible. The aim is to allow users rapid access to all relevant sites, usually at the click of a hot-link button.

The Internet and its use is growing so rapidly that keeping up is a task akin to painting the Forth Bridge – neverending. However, we do believe that we are now well on the way to providing a site that will be the natural starting place for anyone wanting information about the oil and gas industry. The latest tally of hot-linked sites is:

- 36 oil company sites and the Brent Spar site
- 54 associations and institutions
- 47 corporate members of the IP and links to their own sites
- 5 links to links to industry sites
- 4 links to company searches/directories
- 2 standards organisations
- 5 search engines.

Straw in the wind?

Ranger Oil has announced that its 1998 capital expenditure programme has been reduced by \$50mn in the light of the sharp drop in world oil prices since November 1997.

The revised programme of \$235mn includes continuation of the major development activity in the North Sea and Angola scheduled for 1998. High impact exploration drilling in the North Sea and Northwest Territories in Canada also remains unaffected.

The expenditure reduction is in North America with lower exploration spending in Canada and the US Gulf of Mexico and minimal expenditure for heavy oil.

But...

In the latest Gulf of Mexico auction round companies bid \$1.4bn, slightly above last year's \$1.2bn, with successful bids totalling \$810.4mn, only slightly below last year's \$824.1mn. Some 72% of the blocks receiving bids, and 82% of the funds offered, were in water over 1,000 ft deep.

Shell and Conoco jointly made a high bid for a block in 10,581 ft. Deepwater blocks attract royalties of 12% against 16.66% on the shelf. Should the UK Government take note?

NEWS Upstream

Environmental first for Faroe Islands

Acting upon a request from the Faroese Petroleum Administration, 23 oil companies are to undertake an extensive environmental assessment in the seas around the Faroe Islands in advance of the region's forthcoming first licensing round.

The project, known as GEM, will gather data and carry out studies to map the area around the Islands from a geotechnical, environmental and metocean perspective. While such a multi-company, collaborative approach is becoming more usual practice, this is claimed to be the first time that companies have pooled their efforts in advance of a licensing round.

The GEM project is being organised under a steering group comprising three groups: Geotechnical – which will look at the physical conditions of the seabed and immediately below the surface; Environmental – which will consider the animal and plant life living on, or in, the Atlantic around the Faroes; and Metocean – which will gather and assimilate data about the sea conditions in this region. All three groups will draw on both existing data and studies as well as initiating new work.

Participants in GEM are: Agip, Amerada Hess, Amoco, Arco, BP, Conoco, Deminex, DONG, Elf, Enterprise, Esso, Fina, Lasmo, Maersk, Marathon, Mobil, Murphy Eastern, Norsk Hydro, Phillips, Saga, Shell, Statoil and Texaco. The Faroese Oil Administration and the Fisheries Laboratory in the Faroes are also represented on the steering group.

Norwegian projects face one-year delay

The Norwegian Government has proposed a one-year delay in approving 12 new offshore projects in a bid to dampen booming economic growth.

The delayed projects are: Statoil's Gullfaks satellites, Huldra, Heidrun North and Yme Beta West/Epsilon fields; Saga/Statoil's Snorre 2 and H-central and STUJ projects in the Tordis area; Amoco's Valhall water injection project; Norsk Hydro's Fram and Grane fields; and BP's Ula Trias development.

The freeze on new developments is expected to reduce investment demand by NKr5bn in 1998 and NKr12bn in 1999. The proposal has now to be ratified by the Norwegian Parliament, in which the Government is a minority party.

Dana deals with Faroes

Dana Petroleum has entered a five-year strategic partnership with Foroya Kolvetni (FKPF) under which it will provide the Faroese oil and gas company with commercial and technical expertise through the early stages of exploration and development.

Dana will also advise FKPF in negotiations with potential bidding partners targeting the first licensing round. Discussions are already underway with a number of major oil companies. Dana has also been invited to partner FKPF directly in the licensing round. As FKPF's strategic partner, Dana has been awarded an option to acquire an initial 10% stake in the Faroese company. Dana Group Commercial Manager Graham Stewart has been appointed to the board of FKPF.

UK encourages onshore coal-based gas exploration

A total of 35 licences have been awarded to 27 companies for onshore oil and gas exploration covering 120 blocks in the UK's 8th Landward Licensing Round. The majority of the awards are in the East Midlands and southeast England, areas which have previous oil and gas discoveries, such as Cirque Energy's November 1997 oil find at Fiskerton Airfield near Lincoln, and a number of producing fields. Licensees now need to obtain any necessary consents from local planning authorities, who will take account of any environmental concerns, and to agree access terms with landowners before carrying out on-site activities under the licences.

Announcing the awards, UK Science, Energy and Industry Minister John Battle stated that the Government plans to propose new forms of onshore licences to encourage the development of coal-sourced gas reserves. 'There would be environmental benefits from using the considerable quantities of gas from abandoned coalworkings which escapes to atmosphere, where it is 17 times more potent as a greenhouse gas than the exhaust from burning it would be,' he said. 'Although unsuitable as feed to the national gas grid, this gas can be burned locally to generate electricity or to power industrial processes and is a resource which the Government is keen to see used.'

In Brief

United Kingdom

Amerada Hess, Shell and Texaco, *together with partners Esso, Enterprise Oil, Deminex and Hardy Exploration & Production, have received consent from the UK Department of Trade and Industry for the jointly operated development of the Bittern, Guillemot West and Guillemot North West fields in the central North Sea. Peak flow is expected to be 100,000 b/d.*

Gulf Canada Resources is reported to *be selling its North Sea oil assets – acquired as part of the Clyde Petroleum takeover a year ago – to Kerr-McGee Corporation for $590mn.*

Shell and Esso have acquired Saga *Petroleum's 15% interest in North Sea block 16/8c.*

Shell and Esso have completed a North *Sea earn-in agreement under which they have earned a 25% equity interest from Lasmo and Deminex in blocks 14/28b and 14/29b which lie to the north and west of the recently announced Goldeneye discovery.*

Amerada Hess has reached agreement *on the joint development of the Mjolner/Gert field located in Norwegian block 2/12 in the North Sea. Recoverable field reserves are estimated in the region of 20mn barrels.*

Amerada Hess reports that its 20/4b-6 *well has tested at a rate of 41.5mn cf/d and 2,055 barrels of condensate per day, confirming that Shell Expro's Goldeneye discovery extends on to block 20/4b which is operated by Amerada Hess.*

Europe

US company Apache is reported to *have taken a 50% stake in FX Energy's 1.5mn acre concession in the western Carpathian region of southern Poland.*

Results from PetroFina's Tempa *d'Emma 1 well in the Tempa d'Emma concession in southern Italy are reported to indicate a northern extension of the Tempa Rossa field.*

TOTAL is reported to have made a *fourth discovery on block 2/92 off the coast of Angola. The Mutamba-1 well tested at 5,200 b/d of light oil.*

UK tops the E&P popularity stakes

The UK remains the country that international oil companies favour most for new exploration/production ventures in 1998 for the second successive year, despite the competing attractions of ventures in South America and the Caspian, according to Robertson's 12th annual *International New Ventures Survey*.

The UK upstream services and consulting company asked international oil companies across the globe, currently involved in exploration and production ventures outside North America, to rate their level of interest in new ventures in 146 countries. Responses were received from 105 companies which will account for an estimated 70% of total oil company upstream spending in 1998.

The top 10 countries in the rankings were (from the most popular): UK, Australia, Brazil, Kazakhstan, Indonesia, Algeria, Venezuela, Argentina, Egypt and Azerbaijan.

The Far East/Australasia is the most favoured region led by Australia which reached its highest ever position in the rankings. Southeast Asian countries' rankings, however, are generally lower than 1997.

Major advances have been made by Brazil (up eight places from 1997) and Kazakhstan (up eleven places). The central Asian republics, particularly around the Caspian, increased in popularity as a number of gas and oil export pipeline agreements have been agreed in recent months.

A total of 73% of respondents stated that their 1998 total worldwide E&P budgets for 1998 will exceed 1997 levels, while 21% reported that their budgets would remain unchanged, with only 6% indicating a decrease in budget.

The majority of respondents (70%) predicted a 'flat' oil price through 1998 while 19% expect it to fall. An average oil price of $18.60/barrel has been used for 1998 budgeting purposes, down from $18.64/barrel a year ago.

Improving the image of North Sea oil

The UK North Sea industry launched its first ever joint advertising campaign, aimed at the public to explain the enormous scope of the benefits provided to society by oil, on 19 March 1998.

The campaign, branded 'North Sea Oil – We all get a lot out of it', features a variety of products derived from oil and is designed to remind people of the vital everyday uses of oil, in addition to automotive fuel. A series of newspaper and billboard advertisements is being piloted in Scotland for eight weeks.

The campaign also gives the consumer the opportunity to find out more about the contribution that oil and gas companies make to their lives and to the UK economy via a low-rate telephone call or by visiting the website **www.northseaoil.co.uk** – details of which are listed at the bottom of the adverts.

The advertising campaign is being coordinated by the UK Offshore Operators Association (UKOOA) on behalf of its 37 member companies.

According to Steve Harris, UKOOA Director of Communications, the decision was taken to pilot the programme in Scotland, rather than embarking on a nationwide campaign, because the use of television at this stage was felt to be 'premature' and 'Scotland is the only region in the UK that has discrete regional printed media with a wide-enough readership within the population to provide an effective test'.

North Sea Oil was chosen as the 'brand' for the campaign because it is the term that the public uses and understands generically for the offshore oil industry, he continued. 'This may change over time as exploration spreads into other areas and activities of the industry become more widely understood.'

Harris also explained that gas will not be mentioned as part of the advertising campaign because: 'its benefits are widely known and, more importantly, understood by the public. It is a product that has a strong and positive reputation and one that the public is comfortable with using. Research has shown that the public does not have such a good understanding of the oil section of the offshore oil and gas industry.'

Approximately £300,000 is being spent on press advertising and £225,000 on billboards for the pilot campaign. Pre- and post-market research costs are estimated at £20,000.

If the programme proves successful, a national roll-out of the adverts will not necessarily follow. Other options will also be considered, including other regional campaigns or targeting particular interest groups within the population.

In Brief

The European Union is planning to *launch a consultation in spring 1998 of all parties interested in the development of sustainable disposal methods for redundant oil platforms.*

North America

Shell Exploration & Production is *reported to be planning to invest around $1bn on developing the Angus, Europa and Macaroni oil and gas discoveries in the deep waters of the Gulf of Mexico. The three fields are expected to add 300mn boe to Shell's Gulf deep-water reserves. Production is expected to begin from Angus and Macaroni in 1999 and from Europa in 2000.*

Arco Alaska reports that it expects to *spend $2.5bn on oil field development and exploration projects in Alaska over the next five years – an $800mn, or 47% increase over the company's 1997 five-year plan.*

Arco, Exxon and BP have announced *the discovery of two new oil accumulations found during the drilling of a Prudhoe Bay satellite project. The Kuparuk interval, which will become the Midnight Sun field, tested at 4,000 b/d of oil and 1.5mn cf/d of gas while the Sag/Ivishak formation, which will become the Sambuca field, tested 1,400 b/d of oil and 490,000 cf/d of gas.*

Kvaerner Oil & Gas Limited (KOGL) has *signed into an alliance agreement for the development of six gas fields offshore Nova Scotia, Canada, for the Sable Offshore Energy Project (SOEP).*

Phillips Petroleum reports that a fifth *well on its Gulf of Mexico Mahogany field has more that doubled field production to 19,000 b/d.*

Middle East

Two new gas fields are reported to *have been discovered in eastern Saudi Arabia. The Al-Wadhihi and Shama'a fields are thought to have a combined capacity of 23.5mn cf/d.*

Russia & Central Asia

Petergaz has awarded Racal NeSA the *contract for a high resolution ROV route survey for the Russia to Turkey Black Sea gas pipeline. The survey is due for completion in May.*

NEWS Upstream

Conoco and Lukoil sign Russian deal

Conoco and Lukoil have signed a Memorandum of Understanding to proceed with the joint development of petroleum reserves in the 1.2mn acre Northern Territories area of Russia's Timan-Pechora region. Lukoil will hold a 60% participating interest in the area with Conoco holding the remaining 40%.

The formal development plan and the draft production sharing agreement (PSA) are to be delivered to the Ministry of Fuel and Energy no later than mid-December 1998. A request will then be made to Russia's Duma to include the Northern Territories on its list of projects to be developed under PSAs.

The Northern Territories region has three known fields – Yuzhno-Kyhlchuyu (Y-K), Yareiyu and Inzyrei. Reserves are estimated to be over 1bn barrels of oil and 2tn cf of natural gas. Field development is expected to have an estimated $25bn impact on the Russian economy over the life of the project.

Conoco has already invested $100mn to prepare the Y-K field for development and for preliminary evaluation of the other fields and exploration acreage in the block. Preliminary engineering work on the Y-K field indicates that it may require about $2bn in capital costs to develop.

Monument and BP sign Andrew area agreement

Monument Oil and Gas and BP Exploration have signed an agreement for joint exploration in the area around the Andrew and Cyrus oil fields in the central North Sea.

Both companies have identified a number of exploration prospects, including potential satellite developments that can be tied back through the BP-operated Andrew and Cyrus fields. The companies will also undertake a technical review in order to identify and evaluate further opportunities in the farm-in area.

The agreement, which is subject to UK Department of Trade and Industry and co-venturer approvals, allows for Monument to farm in to three blocks – 16/23, 16/28 and 22/3a – by means of funding BP's share of an exploration well programme of up to four wells to be drilled over the term of the agreement. Monument will acquire 50% of BP's equity in each of the three blocks, excluding the Andrew and Cyrus fields. Both companies already share the greater part of the equity in block 16/18 which is adjacent to the farm-in area. First drilling will commence in 1998.

Investing in Rockall Trough exploration

Sixteen major oil companies awarded exploration licences in 1997 for the Rockall Trough recently launched a jointly funded £5.6mn Petroleum Infrastructure Programme (PIP) in Dublin. The programme was welcomed by Irish Minister for the Marine and Natural Resources, Dr Michael Woods as the first development of its kind since the early 1970s.

PIP's aim is to promote surface and subsea exploration by funding oceanographic research in the Atlantic Margin. Divided into two groups, the Offshore Support Group will spend £800,000 on industry infrastructural support for the Irish offshore areas while the Rockall Studies Group will spend £4.8mn over the next four years on the metocean and regional geology of the Rockall Trough.

No oil wells have been drilled in this area but studies show significant hydrocarbon potential as extensions of the West of Shetland and Norwegian fields. Dublin company CSA Group (Oil & Services) will provide a Secretariat for administration and project management for the Rockall Studies Group.

Record number of blocks on offer down under

The Australian Government has released 58 blocks in its 1998 offshore licensing round – a record number reflecting the number of successful discoveries in recent months (see *Petroleum Review*, December 1997). The blocks are located in the Gippsland, Sorrel, Eastern Otway and Western Otway Basins offshore Victoria; the Perth, Carnarvon, Roebuck, Canning, Browse and Bonaparte Basins offshore Western Australia and in the Timor Sea; the Money Shoal, Arafura, Carpentaria and Bamaga Basins offshore the Northern Territory and Queensland.

The closing date for areas NT98-1 to NT98-6, Q981 to Q98-3; V98-1 and V98-5; T98-1 and T98-2; S98-1 and S98-2; W98-1 to W98-3, W98-7 to W98-9, W98-25 to V98-31 is 15 October 1998, and 18 February 1999 for areas AC98-1 to AC98-5; NT98-7 to NT98-10; V98-2 to V98-4; W98-4 to W98-6; W98-10 to W98-24.

In Brief

Schlumberger Geco-Prakla is reported *to have secured the contract for a 1,155 sq km 3D seismic land survey over the Tengizchevroil-operated Tengiz field in Kazakhstan. The seismic programme is expected to run for 12 months.*

Asia-Pacific

Chevron reports that the Gobe oil pro- *ject in Papua New Guinea has come onstream at a combined rate of 10,000 b/d and is expected to reach 50,000 b/d by mid-1998. Reserves from the South East Gobe and Gobe Main fields are estimated at 100mn barrels.*

Esso Production Malaysia's Seligi F *platform offshore Terengganu, Malaysia, is reported to have come onstream and is expected to reach peak production of 21,000 b/d later this year.*

Woodside Petroleum is reported to *have revised down the possible reserves at its Laminaria/Corallina oil and gas field by 23.6% to 216mn barrels.*

Phillips China Inc and Union Texas *Bohai have announced a second oil discovery in the Bozhong block of China's Bohai Bay. The Bozhong 36-2-1 well tested at a maximum rate of 2,262 b/d.*

Latin America

Amoco is reported to have announced *plans to invest $230mn in developing the Amherstia gas field offshore Trinidad & Tobago. First production is expected in 1Q2000.*

Repsol reports that its discovery well *in the Santa Cruz II area of the Austral Basin in Argentina has tested in excess of 3,500 b/d of oil.*

Africa

Exxon is reported to have made a *deep-water oil discovery on block 15 offshore Angola. Its Kissanje well tested at 10,000 b/d each from two of the three producing zones.*

Angolan national oil company *Sonangol and Elf have announced that the Rosa-1 well in block 17 offshore Angola has tested at 12,000 b/d.*

Chevron's Moho Marine No 3 well in *the Haute Mer deep-water area offshore the Republic of Congo has tested at a cumulative rate of 6,800 b/d.*

Green moves in UK budget

Announcing the latest UK Government budget on 17 March 1998, the UK Chancellor Gordon Brown increased the tax on road fuels in line with the government's commitment to raise road fuel duties by at least 6% a year above inflation in a bid to discourage 'unnecessary journeys and encourage fuel efficient vehicles' which, in turn, is expected to produce carbon savings of 1mn t/y by 2001.

He also announced the government's intention to change the structure of taxes on road fuels over time to improve the quality of air in urban areas through two broad objectives: (a) to tax petrol and diesel more fairly, based on the energy and carbon content (this means that the tax on diesel should be higher than that on petrol); (b) to encourage all users of diesel to switch to ultra-low sulfur diesel which is considered to be a significantly cleaner fuel.

As a first step to achieving these objectives, the tax (duty plus VAT) on leaded and unleaded gasoline has been increased by 4.9 p/l (to 49.26 p/l) and 4.4 p/l (to 43.99 p/l) respectively. Ordinary diesel has gone up by 5.5 p/l to 44.99 p/l, while super-unleaded gasoline has risen by 6.1 p/l to 48.76 p/l. The difference in duty between leaded and super-unleaded gasoline has been cut from 1.5p/l to 0.5 p/l, while the duty on leaded gasoline has risen by almost 0.5 p/l more than that on unleaded fuel.

The difference in duty between diesel and ultra-low sulfur diesel (now retailing at 42.99 p/l, up 4.4 p/l) has increased from 1 pence to 2 pence in a bid to further encourage the manufacture and take-up of the latter which produces lower levels of particulates than conventional diesel. At the same time, the specification of ultra-low sulfur diesel is being tightened with respect to density and distillation end point to ensure that this fuel continues to offer 'significant improvements in urban air quality'.

The duty on road fuel gases (LPG and CNG) remains frozen at 21.13 p/kg due to the environmental benefits these gases offer over diesel and, to a lesser extent, petrol. The widened duty differential with conventional diesel offers a clear incentive for high mileage fleets, vans and buses to convert to cleaner gas power and will help offset the cost to motorists of vehicle conversion. In addition, conversion costs will not be taken into account when calculating income tax on car benefit charges.

The combined revenue effects of the duty increases outlined above, on an indexed basis, are expected to be an additional £1,265mn in 1998/99, £1,410mn in 1999/2000 and £1,640mn in 2000/01. The impact of these changes on RPI is estimated to be +0.28%.

Enterprise Oil invests heavily in resource base

UK independent Enterprise Oil announced a dramatic £100mn fall in 1997 pre-tax profits to £255mn from £355mn in 1996. After tax profits, however, at £127mn were only £15mn lower than in 1996.

According to CEO Pierre Jungels, half of the profits fall was attributable to the lower price of crude and half to the strength of sterling against the dollar in 1997. In addition 6,000 boe/d was swapped for an increased holding in the Pierce project distorting the comparison between the two years.

Tax charges were rather lower because lower crude prices at the end of 1997 reduced PRT charges in the UK while lower prices and an increased spend reduced the Norwegian tax liability.

Exploration, appraisal and reserve revisions replaced 181% of 1997's production, and total reserves at year-end were 13% above 1996 levels at 1,126mn boe. The company is investing heavily to develop and expand its resource base. Exploration and acquisition expenditures are planned to be in the £150mn to £170mn range in 1998 following expenditures of £166.2mn in 1997 and £149.3mn in 1996. This year is also expected to see a significant increase in development activity with a planned expenditure of £500mn on a variety of projects in Italy, Norway and the UK. These plans more than double the 1997 development expenditure of £233mn and the £184.4mn spent in 1996.

The second half of 1998 will see the start up of the Pierce and Banff fields in the UK sector of the North Sea and of the Siri field in the Danish sector. In 1999 the first half of the year should see the start up of the Garden Banks 161 field in the Gulf of Mexico. In the second half of 1999 production is due to start from the Bittern field in the UK sector and from the Jotun field in the Norwegian sector while the fourth quarter should see the first phase of the Monte Alpi complex in Italy starting up.

Notionally the Clair field west of Shetland should start up in 2001. However, over recent weeks spokespeople from both BP the operator and Enterprise have hinted that it is the sort of project that is likely to be delayed or even cancelled if low oil prices persist.

In Brief

United Kingdom

The UK Government has announced *that the consultation period for the development of a new North Sea fiscal regime, currently under review, is to be extended, prolonging the uncertainty for North Sea operators. Proposals for change include a broadening of the scope of petroleum revenue tax and abolishing oil and gas royalty payments on the few remaining offshore fields still subject to them.*

Premier Oil reported net profits of *£48.5mn for 1997, an increase of 7% on the previous year. Cash flow rose 45% to £90.5mn and the dividend increased by 10% to 0.605 pence per share. Production rose by 37% to 43,900 b/d. Reserves replacement in 1997 was reported to be 170% to 226.3mn boe.*

Amerada Hess claims to be the first *offshore oil and gas exploration and production company to be awarded international environmental management standard ISO 4001 for the full range of its exploration, development, production and support services in the UK.*

Lasmo plans to pull out of Colombia *and is considering selling its interests in Italy as its existing operations in both countries are considered too small and require high levels of investment. The company also reports that it replaced 227% of production in 1997, at a cost of 66 pence per barrel of reserves booked – total proven and probable reserves now stand at over 1.1bn boe. Lasmo also announced a £184mn operating profit in 1997 on turnover of £722mn.*

Centrica reports that its 1997 turnover *of £7,842mn was £283mn lower than that recorded the previous year. The fall was partly attributed to a drop in fuel demand during the warmer weather of 1997, following a colder than average 1996. Operating profit before exceptional charges rose by £232mn to £175mn, reflecting substantial reductions in operating costs, the firming of gas prices in the commercial/industrial sector and the benefit of lower deferred petroleum revenue tax charges resulting from the adjustment of internal prices on the South Morecambe gas field. Exceptional charges before tax of £835mn comprised £192mn of windfall tax, £608mn in relation to gas contract renegotiations and long-term gas sales agreements and £35mn on restructuring costs.*

Provisional energy statistics for UK

Provisional statistics showing UK energy production and consumption and petroleum product prices in the period November 1997 to January 1998 have been published by the UK Department of Trade and Industry.

A total of 77.4mn toe of indigenous primary fuels were produced in this period, a drop of 4.4% from the level recorded a year earlier. Production of coal (6.9mn toe), oil (37.4mn toe) and gas (27mn toe) fell by 10.1%, 2.5% and 5.5%, respectively. A 5% decrease in primary electricity production* to 6.2mn toe reflected decreased output from nuclear power stations, mainly due to maintenance downtime, with hydro output marginally lower than the previous year.

Total inland consumption of primary fuels during the period November 1997 to January 1998, at 63.5mn toe, was 6.4% lower than that recorded for the same period a year before. Consumption of coal fell by 6.1% to 12.1mn toe, mainly because of reduced use at power stations. Petroleum and gas consumption fell by 7.4% (18.4mn toe) and 6.3% (26.4mn toe), respectively. Gas consumption at power stations was higher than in the corresponding period a year earlier, but demand for gas for heating purposes was lower because of mild weather.

Total use of petroleum, including non-energy use, for the review period was 20.4mn tonnes, a drop of 5.3% from the previous year. Energy use decreased by 7.4% to 15.2mn tonnes while non-energy use increased by 2.7% to 2.8mn tonnes. Gasoline deliveries dropped by 1.8% to 5.4mn tonnes while deliveries of unleaded gasoline rose 5.4%. Unleaded gasoline deliveries in this period represented 74.6% of total gasoline deliveries, compared with 69.6% a year earlier. Diesel fuel deliveries increased by 2.3% while deliveries of other gas diesel oils, primarily used for heating purposes, fell by 11.7% due to milder weather reducing demand. Fuel oil deliveries fell by 37.8% to 3.4mn tonnes.

The statistics also show that between mid-January and mid-February 1998 the price of four-star, premium unleaded and diesel fuels fell by 0.4 pence per litre (p/l), continuing the trend of gradual price drops seen over the previous five months. In the month from mid-December 1997 to mid-January 1998, the price of super unleaded fell by 0.2 p/l, following a rise of 0.1 p/l in the previous period.

In the year to mid-February 1998, rises of 3.2 p/l, 2.5 p/l and 1.6 p/l were recorded for four-star, premium unleaded and diesel fuels. These figures equate to percentage increases of 4.9%, 4.2% and 2.6%, respectively. Over the year to mid-January 1998, the price of super unleaded increased by 6.8%, a rise of 4.7 p/l.

**Primary electricity consists of nuclear electricity, natural glow hydro electricity and, for consumption, net imports of electricity from France. Annual data also include electricity generated from other renewable sources such as wind and photovoltaics. In 1997 primary electricity is estimated to have accounted for about 32% of all electricity available in the UK.*

Pakhoed and Van Ommeren join forces

Royal Pakhoed and Royal Van Ommeren have announced plans to merge their distribution and logistics businesses for the oil, chemical and petrochemical industries. The new company has provisionally been named Vopak and will be headquartered in Rotterdam.

According to Pakhoed and Van Ommeren, Vopak realised a pro forma turnover for 1997 of approximately Fl7bn and an operating profit of Fl600mn. A Fl100mn gross provision is expected to be formed for reorganisation and merger costs. Gross direct cost savings of Fl50mn are forecast over a period of two years. In addition, the companies expect the merger to produce a number of indirect benefits as a result of the optimisation of the investment and acquisition policy. Vopak's main financial target will be an average return on capital employed of 16%.

Some 150 jobs are expected to be lost as a result of the merger, 100 of which will be in the Netherlands. The restructuring programme is not expected to initially effect the company's bulk storage operations in the Rotterdam/Antwerp region. However, the companies have stated that a number of terminals in that area 'may be disposed of in the interests of market efficiency'.

The proposed merger is to be submitted to the European Commission for review.

In Brief

Europe

OMV has sold its remaining 30% *interest in DSM Chemie Linz to DSM as part of a restructuring of the Austrian oil and gas company's chemicals division. The initial 70% was sold to the Dutch chemicals/materials group DSM in early 1996.*

Greece is reported to be planning to *float up to 25% of state-owned oil refining and petroleum products group Hellenic Petroleum in preparation for partial privatisation later this year.*

Spanish oil and gas company Repsol *reports that 1997 net income, after tax, was Pst126,098mn ($827.3mn), up 5.8% from 1996.*

North America

Shell Canada and BHP have announced *plans to undertake a $100mn feasibility study of the proposed C$3.4bn Athabasca oil sands project in Canada.*

Occidental Petroleum has agreed to *sell its Oklahoma oil properties to Anadarko Petroleum for $120mn, its natural gas interests in the West Panhandle field in the Texas Panhandle to Chesapeake Energy Corporation for $105mn, and its natural gas properties in Oklahoma and Kansas, excluding its holdings in the Hugoton field, to Oneok of Tulsa for $135mn.*

EVI has taken over Houston-based *Weatherford Enterra for $2.6bn. Called EVI Weatherford, the new venture is reported to be the world's fourth largest oilfield services company.*

Halliburton and Dresser are reported *to have agreed a strategic merger that will create a new global oil field services and engineering/construction company.*

Ranger Oil reports that total revenues *rose to $351mn in 1997 from $299mn in 1996.*

Occidental Petroleum has reported a *net loss of $884mn for the 4Q1997 compared with net income of $159mn for the 4Q1996.*

Russia & Central Asia

Russia's fourth largest oil company *Tatneft was reported to be planning to list its shares on the New York Stock*

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European oil product demand set to rise

European oil product demand is expected to rise in the 'Big-5' countries of France, Germany, Italy, Spain and the UK by 2.1% in 1998 following a decline of 1.3% in 1997, according to Paris-based analyst Enerfinance.

Mild weather and the accelerated shift away from fuel-produced electricity accounted for the 1.3% drop in product demand in 1997. However, demand is forecast to pick up by 2.1% in 1998. Half of this growth in demand will be the result of a return to 'normal' climatic conditions, states Enerfinance, the remainder coming from general economic growth (climbing from 2.4% to 2.7% on average) and the resulting increase for automotive fuels, and a slowing of the trend to substitute gas for fuel.

This scenario is based on the assumption that the current financial crisis in Asia does not severely affect European economies.

Change in product demand

	1997	1998
France	0.9%	2.6%
Germany	–0.7%	2.0%
Italy	–1.6%	1.3%
Spain	0.6%	4.5%
UK	–5.7%	1.1%
Big-5	**–1.3%**	**2.1%**

Product demand from the Big-5 (mn tonnes)

	1995	1996	1997	97/96	1998	98/97
Gasoline	94.9	94.3	93.6	–0.8%	92.9	–0.7%
Diesel	93.7	95.3	97.9	2.8%	101.6	3.8%
Heating oil	68.6	73.9	70.2	–5.0%	73.0	4.0%
Heavy fuel oil	51.4	48.5	43.9	–9.4%	41.9	–4.6%
Jet fuel	24.2	25.1	26.2	4.2%	27.4	4.5%
Other	84.3	87.9	87.6	–0.4%	91.5	4.5%
Total	**417.2**	**425.0**	**419.4**	**–1.3%**	**428.3**	**2.1%**
Adjusted heating oil*	76.7	75.8	74.7	–1.5%	73.0	–2.2%
Difference	8.1	1.9	4.5	0.0%	0.0	0.0%
Adjusted total	**425.2**	**426.9**	**423.9**	**–0.7%**	**428.3**	**1.1%**

**Adjusted heating oil at normal weather conditions*

New UK natural gas price indexes

Dow Jones has introduced a suite of new indexes tracking the UK's spot market for natural gas. There are three new UK Natural Gas Price Indexes:

- a Day-Ahead Index which is a weighted-average price (pence/therm) of natural gas sold at the national balancing point (NBP) for next day delivery;
- a Weekend Index which is a weighted-average price of natural gas sold at NBP for Saturday and Sunday delivery; and
- a Month-Ahead Index which is a weighted-average price of natural gas sold at NBP for delivery in the next calendar month. (All prices are in pence/therm).

The indexes are based on traded prices collected from more than 20 market participants. They will serve as benchmarks for the UK gas spot market, providing an additional level of transparency in a relatively new and growing market area. According to Dow Jones, the new indexes have several advantages over the current range of comparable benchmark pricing indexes:

- as they are compiled using a weighted average of transactions that have taken place during the trading day, the method used is entirely objective and leaves no room for potential manipulation;
- in contrast to other current UK gas pricing benchmarks, these indexes do not include a subjective assessment of the market at any particular time, and can therefore be relied upon to consistently provide a true reflection of the market;
- all transactions included in the calculations can be fully verified and audited by Dow Jones.

In Brief

United Kingdom

***Kuwait Petroleum (Q8) is introducing** a new pricing structure giving 1 pence off a litre of diesel, regardless of quantity, at 21 of its 'gold' sites and a half pence per litre reduction at 22 'silver' service stations in the UK.*

***Kuwait Petroleum has announced that** it is investing £1mn in the installation of a new vapour recovery unit at its hydrocarbon and chemical terminal at Grangemouth, Scotland, which handles 33,000 road tanker loadings annually, in order to meet EU environmental legislation coming into effect on 1 January 1999.*

***The UK Department of Trade and** Industry has appointed consultants to provide independent advice on the Government's review of energy sources for power generation. Merz and McLellan will provide advice on whether high levels of gas-fired generation could affect the security and stability of the UK's electricity grid, while Wood MacKenzie will advise on the outlook for gas supplies to the UK in the period to 2020.*

Europe

***Spanish oil company Repsol has** unveiled its latest service station forecourt design. The main difference is that the traditional forecourt canopy has been replaced by several canopies shaped like inverted pyramids.*

***Primagaz is reported to have acquired** Esso's butane and propane distribution operations in France.*

***Construction of the Wedal II natural** gas transmission pipeline in Germany is scheduled to begin on 23 March 1998. The pipeline will extend 220 km from Soest to Aachen. Work is to complete by October 1998.*

North America

***Chevron is to pilot a new range of** freshly prepared, pre-packaged and made-to-order meals-to-go for breakfast, lunch or dinner at a number of its service stations in Northern California and the Phoenix area. The Foodini's Fresh Meal Market range will be launched in San Ramon, California later this month.*

NEWS Downstream

Amoco focuses on Egypt and Turkey

Addressing the Mediterranean Gas Conference in Rome last month, Art McHaffie, Vice-President Amoco Energy Development Company, indicated that as the domestic gas grid expanded in Egypt, gas would become available to be sold by the Egyptian General Petroleum Corporation (EGPC) to Inter-Jordan, a joint venture between Amoco, Tractabel and local partners.

Inter-Jordan is to build pipeline infrastructure linking Taba in Sinai to Aqaba and on into Jordan itself. The initial rate of gas deliveries is expected to be 110mn cf/d rising to 350mn cf/d as the grid within Jordan is developed. Development of the pipeline linkages to Taba and Aqaba, and the first shipments of gas, could start by 2001, he said.

He also reported that a sales and purchase agreement for the sale of Egyptian LNG to the Turkish market was now 'well advanced'. The company is currently working with its Egyptian partners, EGPC and Eni of Italy to develop a fast-track project for Egyptian LNG – primarily destined for sale in Turkey. The project would be developed along similar lines to Amoco's single-train LNG plant in Trinidad which is due to commence gas sales in 1999. The Trinidadian project concurrently delineated gas for export, conducted a plant feasibility study, and identified and captured markets, thereby reducing project time to 6½ years versus the more traditional 10 to 14 years for multi-train ventures, he explained. The plant also claims to have one of the lowest unit costs achieved to date in this industry sector.

McHaffie also said that Amoco was committed to fulfilling domestic Egyptian demand and, with Eni, was already developing in excess of 1tn cf of gas in the Ha'py field in the Delta for onstream deliveries to the Egyptian gas grid in 1999. Additional development plans for fields to supply the domestic market have been submitted to EGPC.

February fuel prices

	Pence per litre
Diesel	
Lowest: Norwich	60.69
Highest: Cambridge	65.36
National average	63.23
Unleaded petrol	
Lowest: Norwich	60.42
Highest: Inverness	65.44
National average	63.11
Four-star petrol	
Lowest: Halifax	65.86
Highest: Aberystwyth	72.31
National average	68.66

Source: *PHH Allstar Fuel Report*

In Brief

***Gas Natural Mexico, a gas distribution** company in which Repsol and Gas Natural SDG each hold a 50% stake, has won a concession to distribute natural gas in Monterrey, the second largest industrial zone in Mexico.*

***Kinder Morgan has acquired west** coast refined products carrier Santa Fe Pacific Pipeline for $85mn. The deal is claimed to make Kinder Morgan the second largest pipeline system owner/operator in the US.*

Russia & Central Asia

***State-owned airline Kyrgyz Airways is** reported to have signed an agreement with Texan company Manas Refinery Partners to build and operate a $35mn, 400,000 t/y (approximately 8,000 b/d) oil refinery near Bishkek, Kyrgyzstan's capital city. The plant, which will cover the airline's jet fuel needs as well as produce gasoline and diesel fuels, will be commissioned in May 1999.*

***Silmet Grupp of Estonia is reported to** have announced plans to build a transit oil port and refinery at Sillamea in northeast Estonia. The port will handle Russian petroleum products and up to 10mn tonnes of dry cargo.*

***Hungarian oil and gas company Mol** has signed a Ft10bn ($47.8mn) syndicate loan agreement that will be used partly to finance the implementation of the delayed Ft49bn coker and hydrogen plant scheduled for construction at the Duna refinery.*

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UK Deliveries into Consumption (tonnes)

Products	†Jan 1997	*Jan 1998	†Jan 1997	*Jan 1998	% Change
Naphtha/LDF	173,613	316,176	173,613	316,176	82
ATF – Kerosene	599,747	644,279	599,747	644,279	7
Petrol	1,716,587	1,733,432	1,716,587	1,733,432	1
of which unleaded	1,197,953	1,306,534	1,197,953	1,306,534	9
of which Super unleaded	41,288	34,098	41,288	34,098	-17
Premium unleaded	1,156,665	1,272,436	1,156,665	1,272,436	10
Burning Oil	436,865	351,165	436,865	351,165	-20
Derv Fuel	1,165,506	1,202,330	1,165,506	1,202,330	3
Gas/Diesel Oil	834,870	651,768	834,870	651,768	-22
Fuel Oil	545,851	250,000	545,851	250,000	-54
Lubricating Oil	72,639	68,191	72,639	68,191	-6
Other Products	715,426	756,093	715,426	756,093	6
Total above	6,261,104	5,973,434	6,261,104	5,973,434	-5
Refinery Consumption	565,642	503,021	565,642	503,021	-11
Total all products	6,826,746	6,476,455	6,826,746	6,476,455	-5

† Revised with adjustments *preliminary

cont'd from p7

Exchange in late March. The company holds a number of oil interests in the Republic of Tatarstan and is said to have proven reserves of 855mn tonnes.

Yuksi, the recently formed Yukos and *Sibneft Russian oil company joint venture, is bringing forward various cost cutting and efficiency plans announced at the merger in response to the falling international oil price. Measures include: outsourcing non-core activities such as drilling and other field services; a 5% reduction in total group costs and a 30% cut in total salary costs; a 5% reduction in production; implementation of a new distribution strategy to increase sales through its own outlets by 10% a 5% reduction in transport costs; and a reduction of refining capacity to focus on profitable product mix and local markets.*

Dublin-based oil company Dragon Oil *is reported to be planning to invest up to $45mn on development and new wells in Turkmenistan in 1998. The company has also put forward a joint proposal for the construction of a 2.5bn cm/y capacity gas export pipeline linking Turkmenistan and Kazakhstan.*

The Ukrainian Government is reported *to be planning to create a new state oil and gas firm as part of a restructuring of the country's oil and gas sector. The new company – Naftohaz Ukrainy – will replace the former state-owned oil and gas committee.*

Asia-Pacific

The Expro Group has acquired *Australian subsea engineering company Subsea Service as part of a drive to expand its upstream/downstream support services business in Australia and the Asia-Pacific region.*

Repsol has agreed with Overseas Oil & *Gas Corporation, a subsidiary of China National Offshore Oil Corporation, the sale of three companies – Repsol (Java), Repsol (Sumatra) E&P and Repsol Exploracion Sunda – which hold the Spanish company's exploration and production assets in Indonesia.*

Latin America

The Argentinian Government is *reported to be planning to sell its remaining 20% stake in oil company YPF and its interests in all other privatised companies.*

Cory Towage has been awarded a *contract to provide towage and fire fighting services at Jose and Puerto la Cruz in Pozuelos Bay by PdVSA-PDV Marina of Venezuela.*

Africa

Nigeria is seeking an international *court ruling on a border dispute between itself and Cameroon over the Bakassi peninsular which is thought to contain significant oil reserves. Cameroon currently occupies the disputed acreage. Nigeria has also called for the International Court of Justice to rule on another disputed frontier surrounding Lake Chad which Cameroon claims is currently unlawfully occupied by Nigeria.*

Soco International has purchased *Coplex Resources' minority interest in Comeco Petroleum, a corporate entity through which Soco holds an 11.785% stake in the East Shabwa Development Area in Yemen. Production from East Shabwa is approximately 20,000 b/d.*

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Chevron and Caspian TransCo have *entered into an agreement with the Republic of Georgia which gives the two companies the right to use and operate Georgian oil transportation facilities from the Georgian town of Khashuri to the port of Batumi on the Black Sea.*

Shell Exploration and the Government *of Turkmenistan have signed a Memorandum of Understanding to promote a project to export gas from Turkmenistan to Turkey. Shell is to undertake a feasibility study of the proposed gas pipeline.*

Asia-Pacific

Woodside Petroleum is reported to be *seeking permission to construct a 2.5 mn t/y LNG gas import terminal and 1,800 MW power station in the state of Tamil Nadu, southeast India.*

US controlled company Epic Energy *Australia is reported to have acquired the 1,530-km Dampier-to-Bunbury pipeline in Western Australia for $2.4bn.*

Apache is reported to have signed an *agreement to supply 700bn cm of natural gas to An Feng Kingstream Steel in Western Australia for a 15-year period beginning July 2000.*

Africa

TOTAL and the Nigerian National *Petroleum Corporation have signed an agreement to rehabilitate the 110,000 b/d capacity Kaduna refinery located 700 km northeast of Lagos. The project is expected to cost $200mn.*

General

Italian oil company Agip Petroli and *IBM of the US are reported to be planning to jointly develop and apply innovative IT technology for managing refining processes.*

UK company Solapak has announced *its largest ever photovoltaic (solar) power system design and supply contract in its 20-year history. The 30 metres long array will provide 9 kWp (nine kilowatts at peak output) for MAN GmbH in a remote area of North Africa.*

Mexican state-owned oil company *Pemex is reported to be forging alliances with a number of US refiners. Deals include the signing of a long-term supply contract with Clark USA which is to build a new coking plant at its Texan Port Arthur refinery. Discussions are also reported to have taken place with Mobil Oil for the supply of heavy crude to the oil company's Beaumont, Texas, refinery.*

PHOTOGRAPHERS WANTED

Shell Bitumen is offering £1,000 to the winner of a photographic competition to find Britain's biggest, busiest and most beautiful asphalt roads.

There are four categories: big roads, busy roads, beautiful roads, and creative road shots. Photographers can enter as many photos as they wish. Each category winner will receive £150, in addition to the £1,000 prize for the overall winner.

Run in conjunction with *Local Government News*, the competition is open until 30 April 1998.

European gas demand falls in 1997

Natural gas consumption in Western Europe dropped 1.5% in 1997, according to preliminary estimates just published by Eurogas. Spain, supplied by the newly completed Maghreb-Europe Gas (MEG) pipeline, stood out as an exception, showing an increase of 33% on year-earlier levels. If Spain is excluded, statistics for the rest of Western Europe indicate consumption fell 2.5%, reports *Fred Thackeray*.

The 1997 demand fall is easily dismissed as the consequence of lower residential heating demand due to much warmer weather than in 1996. But in the context of all the hype about liberalising EU gas markets, such a lacklustre performance begs a more critical look. In particular, can markets develop to absorb the increasing capacity to supply gas from Russia, Norway and Algeria – as well as the samller but significant volumes that are becoming available from a number of new sources? The decline in consumption last year followed growth of 50%, or 4.6%/y, in the 1987–1996 period. In 1996 alone consumption grew by about 5.5%. The strong growth in recent years has created widespread interest in where and how newcomers may find a niche in the liberalising markets. By comparison with the oil markets, the increase in natural gas usage is indeed remarkable. In the period 1987–1996, when gas consumption jumped 50%, oil consumption in the same countries increased by a mere 9% or an average of 1%/y. The petroleum product which fared worst was fuel oil. Inland demand plus bunkers actually registered a consumption drop of over 9% between 1987 and 1996.

If the 1997 gas estimates are dampening, so also are Eurogas' forecasts. For the same countries as covered in the accompanying **Table** (and its footnote) the growth of consumption is predicted at an average 2.7%/y 1996–2005, 0.85%/y 2005–2010 and 0.7%/y 2010–2020. By the last-named date, i.e. in 23 years time, it is forecast to reach 435mn toe or about 519bn cm as compared with 351bn cm in 1997.

As shown in the **Table** the rates of change in gas consumption have varied widely between countries, both last year and during the period since 1987. The figures are dominated by those for the bigger economies, with consumption in the UK rising most rapidly and surpassing Germany for the first time in 1997. Until a few years ago all European countries were affected by the 'energy policy' view that natural gas is a 'noble' fuel and that it should be conserved and not used for power generation. With the demise of this view, coupled with the progress of Combined Cycle Gas Turbine (CCGT) technology and growing appreciation of the environmental benefits of using gas, the scene has changed radically.

The effects of this change have been experienced most strongly in the UK, where rapidly expanding consumption of gas to generate power has increased this usage to more than 20% of total consumption. In 1996, UK consumption by power plants accounted for close to two-fifths of the total used by power plants in all West European countries. The extent to which power generation consumption of gas expands in the rest of Western Europe – particularly in Germany – will be a major factor, which could result in the next 10 to 15 years in faster growth than is at present forecast by Eurogas.

In bn cm*	1987	1996	1997	% change (avge) 96-97	87-96
Austria	5.1	8.1	7.8	*(3.8)*	*5.3*
Belgium	9.4	14.1	13.4	*(4.6)*	*4.6*
Denmark	1.5	4.0	4.1	*3.4*	*11.5*
Finland	1.5	3.5**	3.5**	*(2.4)*	*9.9*
France	27.8	38.7	37.1	*(3.9)*	*3.7*
Germany	59.1	85.4	80.6	*(5.4)*	*4.2*
Ireland	1.5	3.2	3.3	*4.5*	*8.8*
Italy	35.8	54.9	56.4	*2.9*	*4.9*
Netherlands	37.3	44.4	41.6	*(6.1)*	*2.0*
Spain	3.0	9.9	13.2	*32.7*	*14.0*
Sweden	0.3	1.0 **	1.0**	*(0.3)*	*14.3*
Switzerland	1.0	2.8	2.7	*(3.8)*	*12.1*
UK	54.1	85.3	84.5	*(0.7)*	*8.5*
Total* **	**237.4**	**356**	**351**	***(1.5)***	***4.6***

**Figures for 1996 and 1997 converted from Eurogas estimates in petajoules on basis of 39 megajoules=1cm. ** Rounded.*
****Greece, Portugal and Luxembourg included in Eurogas forecasts but negligible in 1997.*
Sources: 1987, BP Annual Review of Energy Statistics; 1996 and 1997, Eurogas

Consumption of natural gas in Western Europe

Booming demand, production and reserves

For the international oil and gas industry, Latin America represents one of the most exciting areas in the world. Following the 'lost decade' of the 1980s when the debt crisis and political upheaval depressed economic activity and energy demand, the area is now growing and prospering.

Possibly even more important is the fact that the aggressive nationalism that produced the state-owned monopoly oil and gas companies has now given way to a recognition of the benefits of inward investments and the efficiency gains to be derived from privatisation and decontrol. **Table 1** shows the way that all the countries in the region have moved in this direction with Argentina having levels of private ownership and decontrol similar to those in western Europe and North America.

Energy demand in the region averages only a quarter of OECD levels but rapid economic growth and a close linkage between economic growth and energy usage means that demand has been rising at around 5%/y and is expected to continue at this rate. Full details of reserves and production of both oil and gas, as well as current refining capacity, are shown in **Table 2**.

Energy supplies are dominated by oil and gas which account for roughly 50% and 20% of the region's energy mix. Over the last decade regional and consumption growth has averaged 2.6%/y, slightly above GDP growth rates and well above the world average growth rate of 1.4%/y. Oil production, however, has expanded by 55% over the 1986 to 1996 period compared with a world growth of 14%. Production gains have been roughly twice the growth in regional consumption allowing regional exports to increase significantly. The point is now being approached where Canadian and South American oil exports are virtually equivalent to US imports (see article by Prof Odell, *Petroleum Review*, February 1998). The great gains in oil production have been achieved by privatisation and price decontrol (Argentina), increased involvement of western companies and technology (Venezuela), major new discoveries (Colombia) and the opening up of deep-water production (Brazil).

The gas industry represents an even greater success with production and consumption rising fast. Generally the gas market in Latin America is very underdeveloped with only limited delivery infrastructure. The notable exceptions to this are Argentina where gas accounts for 49% of energy demand and Venezuela where it accounts for 48%. The regional average is, however, only 19%. The region is starting to build a

	Upstream	Refining	Retail	State Oil Co	Retail Prices Gasoline	Gas
Argentina	dereg '89	dereg '89	dereg '89	Privatised	dereg	reg
Bolivia	Assoc contracts with YPFB	state owned	dereg	'capitalised'	dereg by 2001	reg
Brazil	progressive dereg from '97	partial reg	State control, private shareholders		reg reg	reg reg
Chile	N/A	state owned	dereg	state owned	dereg	reg
Colombia	Assoc contracts with Ecopetrol	owned by Ecopetrol	dereg	state owned	reg	reg
Ecuador	Assoc contracts with PetroEcuador	owned by PetroEcuador	dereg	partially privatised (by subsidiary)	dereg	reg
Peru	Contract with Govt	partially privatised	dereg	partially privatised	reg	reg
Venezuela	PSC with PDV	owned by PDV	dereg	state owned	reg	reg

Source: ING Barings

Table 1: Deregulation by country

	Oil reserves bn barrels	R/P ratio years	Oil prodn '000 b/d	95–96 %	oil cons '000 b/d	95–96 %
Argentina	2.4	8.2	805.0	7.4	445.0	4.9
Bolivia	0.12 (a)	11 (a)			*	
Brazil	4.8	16.5	800.0	13.5	1,600.0	7.1
Chile					225.0	8.6
Colombia	2.8	12.1	635.0	7.4	275.0	3.7
Ecuador	2.1	14.8	395.0	–0.2	*	
Neth Antilles						
Peru	0.8	18.3	120.0	–1.4	*	
Trin and Tob	0.6	11.3	140.0	–1.3	*	
Venezuela	64.9	57.5	3,145.0	6.6	425.0	–5.3
Other	0.8	22.9	100.0	5.9	1,365.0	4.0
Region total	**79.2**	**36.1**	**6,140.0**	**6.8**	**4,335.0**	**4.4**

*Note: *Not broken down, included in 'Other'*
Sources: All figures from 1997 BP Statistical Review *unless otherwise indicated*
(a) ING Barings, Latin America: Fuelling the Future

Table 2: Latin America: production, consumption and refining capacity

pipeline infrastructure with the Southern Cone featuring a number of new supply lines (see **Table 3**). Major gas resources in Bolivia and Peru are currently locked in for lack of delivery infrastructure. As the new pipelines are completed gas demand is expected to soar and gas could provide 28% of the region's energy needs by 2001. Gas demand growth has averaged over 5% over the last decade and this rate of growth is expected to continue. With 70 years of proven gas supplies and per capita consumption running at a fifth of the OECD average, prospects for the Latin American gas industry look very bright indeed.

The region in the 1990s is now characterised by rapid economic and energy growth and stable democratic governments. There is an increasing acceptance of private ownership and decontrolled markets making the area one of the most interesting opportunities for the international oil and gas industry. *Petroleum Review* would like to extend particular thanks to Christophe Chew of ING Barins for allowing us to draw on and reproduce tables from the company's report *Latin America: Fuelling the Future.*

Argentina

Argentina is Latin America's largest energy market after Brazil. Around 46% of domestic energy demand is met by gas – more than double the regional average. Energy demand is forecast to increase by 6% per year to around 73mn toe by 2001.

It has proven oil reserves of 2.4bn barrels and 0.62tn cm of gas reserves. The main producing basins are Neuquen to the west of central Argentina, the Gulf of San Jorge off the southeast coast and the Austral Basin in the far south. Many of the recent new finds have been gas rather than oil and, as a result, oil production is forecast to rise by just 1% to 1.5% per year to 42mn tonnes by 2001. However, this will still be enough to ensure that the country remains a net exporter in the immediate future. The country currently produces some 41mn tonnes per year of oil – double its domestic requirement. The key export markets are Brazil, Chile and the US.

Gas consumption has increased by 80% over the past ten years while production has risen by 90%. There is an extensive gas transmission and distribution system, operated by TGS and TGN, and eight distribution companies. Gas is exported to Chile via the Gas Andes pipeline which was came onstream in 1997. The gas markets of Brazil, Uruguay and Paraguay are expected to open up as Latin America's pipeline infrastructure is developed.

Both domestic oil and gas production have the potential to increase substantially. However, any expansion programme will be dependent upon the development of more pipeline capacity. Planned projects include a 280-km, 8mn cm/d capacity pipeline to Chile, being built at a cost of US$350mn and due to be commissioned this year, and a 1,700-km, 31mn cm/d capacity pipeline linking the country with Brazil, costing US$700mn and scheduled to come onstream in 2005.

Argentina is the most fully deregulated country in the region. However, despite the success of deregulation, foreign interest has been somewhat disappointing and some 80% of the country remains unexplored. The government is trying to encourage exploration by offering better incentives to both foreign and indigenous companies. However, multinationals may well opt to invest in other countries until the Argentine government approves a new hydrocarbons law, which was drafted and submitted three years ago, and puts in place a more stable legal and fiscal environment. That said, US company Amoco and Bridas of Argentina recently merged their oil and gas businesses to create what is claimed to be the second largest oil and gas company in the country (YPF, the former state-owned monopoly, being the largest).

Bolivia

Gas is Bolivia's key resource, with reserves of 1.3tn cm equivalent to 40 years' production. Production is expected to increase considerably once exports to Brazil commence following the commissioning of the 3,400-km Bolivia-Brazil pipeline in 1999. Under a 20-year agreement signed in 1993, around 8mn cm/d of Bolivian gas will be supplied to Brazil for the first 7 years, rising to 28mn cm/d for the remaining 13 years of the contract.

Plans are to ultimately double Bolivia's gas production from its current rate of 8.86mn cm/d (3.2bn cm/y). Foreign interest has increased in the region now that plans are in place to open up the Brazilian gas market – key players include Shell, YPF, Exxon and Total. Gas exports are forecast to rise to 11bn cm by 2005.

Bolivia plans to become a hub for gas transfers in Latin America in the future with pipelines planned to link the country to Chile, Peru and Paraguay. Such projects are likely to stimulate further foreign interest.

Proven oil reserves of 0.12bn barrels are sufficient to last 11 years at current production rates. The domestic market for oil remains small and is growing at 2.8% – slower than the GDP growth rate of 3.65%. Gas consumption is expected to grow more rapidly in com-

	Refin Cap ,000 b/d	95-96 %	Gas reserves tn cm	R/P ratio years	Gas prodn bn cm	95-96 %	Gas cons bn cm	95-96 %
Argentina	665.0	0.6	0.62	21.4	29.0	15.5	31.0	14.6
Bolivia			0.13	40.1	3.2	1.0	1.6 (a)	
Brazil	1,540.0		0.15	28.9	5.3	7.5	5.3	6.1
Chile							1.7	3.3
Colombia			0.23	49.7	4.7	6.8	4.7	6.8
Ecuador			0.10	100+			*	
Neth Antilles	490.0						*	
Peru			0.28(a)				*	
Trin and Tob	260.0		0.35	49.6	7.1	15.3	*	
Venezuela	1,280.0		4.01	100+	32.0	7.5	32.0	6.7
Other	2,135.0	0.4	0.30	100+	2.8	3.8	9.3	12.3
Region total	**6,370.0**	**0.2**	**5.89**	**70.2**	**84.1**	**10.3**	**84.0**	**10.0**

*Note: *Not broken down, included in 'Other'*
Sources: All figures from 1997 BP Statistical Review *unless otherwise indicated*
(a) ING Barings, Latin America: Fuelling the Future

Table 2 continued: Latin America: production, consumption and refining capacity

Route	Length (km)	Capacity (mn cm/d)	Cost (US$mn)	Completion (est)
Bolivia-Chile	700	5.6	300	1998
Argentina-Brazil	1,700	31	700	2005
Argentina-Chile	280	8	350	1998
Chile	700	N/A	N/A	2015
Peru-Bolivia	808	18	700	2010
Bolivia-Paraguay	560	2	86	1998

Source: YPFB

Table 3: Southern cone gas grid: projected pipelines

parison. The main production areas are the sub-Andean and Pie de Monte Basins in central and southern Bolivia.

Bolivia's energy industry is currently being privatised in a phased programme through a capitalisation (public and private cooperative ownership) process.

Brazil

Brazil has the highest energy demand of all the Latin American countries. Crude oil and refined products imports, primarily sourced from Argentina, Saudi Arabia and Venezuela, account for 40% of consumption. Although its energy industry is slowly being deregulated in a bid to boost domestic oil production – Petrobras is reported to be targeting an increase of 11.6% to 81mn tonnes by 2001 – the country is expected to remain heavily dependent on energy imports for the foreseeable future.

Total energy growth is predicted to rise by 4.5% per annum with oil demand forecast to rise by 3% per year and gas consumption increasing by a massive 22% per annum as more gas fields come onstream and Bolivian gas supplies become available.

Brazil's deep-water Campos Basin fields, which first started production in 1977, account for two-thirds of the country's annual production, and proven oil reserves are now estimated at 14bn barrels. Recent production increases, and most of the later discoveries such as Albacora, Marlim and Barracuda, have extended the size and extent of the basin.

State-owned Petrobras is a world leader in deep-water technology, able to produce routinely at depths of over 1,200 metres (see article p16). However, such operations are costly, and future developments may not be viable if the oil price remains low or continues to fall as has been the trend in recent months (see Editorial p2).

Recent milestones include test production from the Marlim Sul at the world's current production depth record of 1,709 metres in September 1997. Fields due onstream in 1998 include Voador and Albacora as well as a significant extension of the Marlim field. Projects due onstream in 1999 include Marlim Sul and the 1,300-metre water depth Roncador field which has reserves of 3bn boe and is said to be the first field in the Campos Basin to have high quality oil. The Espadarte pilot offshore field, to be developed by a floating production system and originally expected to be commissioned in the 1Q1999, is reported to have been shelved while another, potentially larger discovery, to the south of the field is re-evaluated.

Some 5% (11bn cm/y) of Brazil's total energy requirements are expected to be met by Bolivian gas in 2005 following the commissioning of the US$1.9bn, 2,908km Bolivia-Brazil pipeline. A 1,700-km, 11bn cm/y pipeline linking Argentina to Porto Alegria in southern Brazil via Uruguay is also under discussion as is an extension of the Camisea (Peru) pipeline to Brazil.

Although some steps have been taken towards deregulation of Brazil's oil industry with the signing of a new law in August 1997, the absence of a clear mechanism is expected to lead to slippage in the programme and disputes. At present, it seems that any strategic industry decisions will be handled by the national energy policy council CNPP (headed by the Minister of Mining and Energy) while oil policy will be implemented by the national petroleum agency ANP which will also be responsible for regulating and controlling the industry.

Petrobras is the second largest oil company in Latin America after PdVSA, and the largest listed company in any sector. Worldwide, it ranks 9th in terms of refining capacity and 19th in terms of oil reserves. The company's monopoly over the bulk of Brazil's oil and gas industry is currently being abolished in a phased programme in order to allow it to prepare for competition. However, it is more than likely that Petrobras will remain the dominant player in the Brazilian marketplace as its size and proactive move to create joint venture companies, both upstream and downstream, will allow it to retain a considerable degree of control as the industry deregulates.

Chile

Unlike its Latin American neighbours, Chile has no significant domestic oil and gas reserves. It is almost completely dependent on imports to meet its domestic energy requirements – only 8% of oil consumption is met by domestic production. Argentina is Chile's main gas supplier and there are plans to link the two countries, electricity grids. Argentina is also Chile's main oil importer, supplying 53% of the country's needs, followed by Nigeria (13%), Angola (10%) and Venezuela (8%).

The region is still relatively underexplored, and, in light of some recent large field discoveries, Ing Barings states that the rewards for increased exploration investments could be high. The country's economic outlook is good and its energy market is one of the fastest growing in the region. Demand for transport fuels, usually a good indication of economic prospects, is forecast to expand by more than 6% per year.

The commissioning last year of the 5.3mn cm/d capacity Gas Andes pipeline linking Chile and Argentina is expected to transform Chile's energy economy. The 465-km pipeline currently carries some 1.5 cm/d of gas from La Mora in Argentina to Santiago. Gas demand is predicted to increase by over 15% per annum over the next five years, underpinned by official policy to increase gas-fired electricity generation and expand both domestic and industrial use, and gas imports are forecast to rise to 1.8bn cm/y by 2001.

Colombia

Colombia is a major exporter of oil, consuming just 12.6mn t/y of its 32.4mn t/y production. Its domestic industry is founded on the large BP-operated Cusiana/Cupiagua field in the Llanos Basin to the east of the Andes, which tripled the country's reserves base upon its discovery in the late 1980s. Proved oil reserves are 2.8bn barrels and 0.23tn cm of gas. Six new oil finds in northern, central and eastern Colombia were announced by state-owned Ecopetrol as *Petroleum Review* went to press. The best finds were reported to be in the eastern Piedemonte and the Middle Magdalena regions.

Around 60% of the country's 32.4mn t/y of oil production is exported while all produced gas is consumed by the domestic market. Recent large gas discoveries are expected to underpin a national gas plan to invest in excess of US$3bn over the next 15 years on new gas transmission and distribution facilities, and the installation of 1.7GW of gas-fired generating capacity, together with a doubling of domestic gas consumption by 2000. Long-term domestic gas consumption is put at 14% per annum.

The country has been beset by political problems which, combined with burdensome upstream terms and Ecopetrol's problems with meeting its share of exploration and production costs, has discouraged many foreign players from entering this exploration arena. Despite this, the government hopes to attract US$4bn of upstream investment over the next five years.

Although state oil company Ecopetrol's monopoly is now restricted to refining and wholesale distribution, early privatisation is not considered likely.

Ecuador

Ecuador represents one of the smallest energy markets in this region. Over 60% of production from the Oriente Basin Andes (proved oil reserves of 2.1bn barrels) to the east of the Andes is exported. Oil demand is forecast to grow by 3% to 4% per annum in line with economic growth. Demand for transport fuel is expected to rise by 6% per year.

Plans to boost oil production by 30% over the next five years stand little chance of being achieved unless the capacity of the 350,000 b/d Trans-Ecuadorian pipeline system, linking the country's oil-fields to the coast, is expanded. This looks unlikely to happen in the near future.

Gas reserves are small – 0.10tn cm. At present there is no gas production as a domestic gas market has yet to be developed.

Ecuador's energy industry is slowly being liberalised and foreign operators currently account for around 22% of production.

Peru

Gas is of key importance to Peru's energy sector. Its large Camisea gas field, discovered in the southeast of the country in the 1980s, has recoverable gas reserves estimated at 10tn cf and 600mn barrels of condensate. Field development is expected to cost in the region of US$3bn over the next seven years. A final decision by Shell and Mobil has yet to be taken over full field development, however, a market for the gas has yet to be found. At present, initial production is targeted for 1999, with first gas deliveries to Lima in 2002 following the construction of a twin gas line over the Andes. If field development does proceed as planned, it is expected to stimulate a massive expansion in gas-fired generation capacity in the country.

According to ING Barings, domestic gas consumption could grow by over 10% per annum – compared with total energy demand growth of less than 6% per year. However, any expansion programme may be inhibited by the government's refusal to guarantee market access or to allow exports which, in turn, are hindering investment in parts of the Trans-Andes transmission system.

Peru is very dependent on oil, which meets 76% of the country's current energy needs. Some 20% is imported, the rest produced from the country's fields located along the eastern side of the Andes which have proved reserves of 800mn barrels. Production in 1997 averaged 120,000 b/d.

Privatisation of the country's energy industry has been relatively piecemeal to date and further progress may be delayed following a recent change of government.

Trinidad and Tobago

Trinidad and Tobago's major oil fields, Soldado, Teak and Poi are in decline and although some smaller oil fields may be developed over the next few years, LNG development is the key priority. Liquids associated with gas development may help offset the decline in oil production. Almost half of the region's oil output is exported to the US.

Development of the Dolphin gas/condensate field and Amoco's Atlantic LNG project at Point Fortin are expected to generate significant liquids production before 2000, as the project is being fast-tracked to reach European and US markets before other larger LNG projects in the Atlantic Basin come onstream (see p9).

It has recently been reported that private sector investors are being sought by Trinidad and Tobago, and Venezuela, for the Tajali, Luran and Cocuina gasfields lying in the waters separating the two countries. It is thought that Brazil would be the target market.

Venezuela

Holding 6.2% of the world's proven oil reserves, Venezuela dominates Latin America's oil industry in terms of both reserves and production. The largest reserves lie in and around Lake Maracaibo; others are located in the San Joaquin and Oficina regions to the east of the country. Government plans to double oil production to 7mn b/d by 2005 are heavily dependent on increased levels of foreign capital and expertise, together with some degree of market liberalisation. Current oil production is 155mn t/y, compared with 20mn t/y of domestic demand. Some 135mn t/y is exported (primarily to the US and Brazil), a quarter of this as refined products, and the remainder as crude oil.

Venezuela is also a major gas producer. The bulk of it's 4tn cm of gas reserves are associated with its oil, and their development is thus secondary to oil. Most of the gas is produced from the Maracaibo, Guarico Oriente and Cariaco Paria fields, the bulk of production going to the domestic market. Gas production growth is expected to remain at 4% per annum until the much delayed Cristobal Colon LNG project comes onstream. Natural gas is forecast to play an increasing role in Venezuela's energy economy. Consumption is predicted to rise by 30% by 2000, rising a further 10% by 2005. A number of gas transmission and distribution, and LPG schemes have been identified and there are plans to expand the country's gas-based petrochemicals sector.

Venezuela's largely unexploited Orinoco Basin heavy oil resources – which some believe could be larger than Saudi Arabia's current 260bn barrels of proven reserves – could prove to be of major importance to the country in the future. Economic extraction of the oil has been difficult in the past, but recent improvements in cracking technology – originally developed to upgrade Canadian tar sands – have reduced the cost of upgrading Orinoco oil to a light synthetic crude to US$3/barrel compared with a crude value of around US$13/barrel. New pipeline infrastructure linking the Orinoco Basin to the coast would be required to underpin any such development plans. A number of US companies, including Exxon, Arco, Texaco, Phillips and Mobil have interests in this region.

The country has a well developed gas transmission system linking its gas fields to the main industrial consumers. This will be further extended at the 6mn t/y Cristobal Colon LNG export terminal and other cities are connected to the network.

Other pipeline schemes include a proposed 3,190-km, 300,000 b/d oil pipeline linking eastern Venezuela to Florida. The US$3.6bn pipeline would include spurs to Puerto Rico, the Dominican Republic and Cuba. However, the pipeline may be shelved until relations between the US and Cuba improve.

State oil company PdVSA recently embarked on a restructuring programme in a bid to improve operational efficiency and competitiveness. As part of this programme, PdVSA's refining assets will be consolidated into a single company. Domestic refining capacity is to be expanded to 150mn t/y, and overseas capacity by 80% to 80mn t/y, in order to maintain product export volumes as oil production doubles in line with government plans.

Venezuela is the only Latin American member of Opec. However, its drive to expand production beyond the official Opec ceiling and its refusal to attend a recent meeting (see Editorial, p2) have strained the relationship and it remains to be seen whether the country continues to remain a member if it is no longer deriving any benefit.

New production to come from ever deeper water

Oil and gas production in Brazil started in 1939. In 1968, the first offshore area was discovered. Peak production during this period was around 150,000 b/d with production, at this date, limited to onshore areas. However, since the discovery of the highly prospective Campos Basin in the early 1970s Brazil has become a leader in the development of deep-water fields. Later this year it is set to recapture the production depth record with the start-up of production from the Roncador field in 1,709 metres of water. Following is a slightly shortened version of the Petrobras presentation at the IP's Innovations in Offshore Field Developments conference held during IP week in mid-February. It details Petrobras' latest developments in the Campos Basin and its ambitious plans for the future.

Petrobras began offshore production in 1973 in the Sergipe-Alagoas Basin. The water depth of around 30 metres represented quite a challenge at that time. Many similar installations in the northern part of the country were then installed. The usual solution was to install a jacket and a deck with topside facilities. Jack-up drilling in cantilever mode or tender ship assisted drilling was used. The process was very simple, and the production stream was sent to shore through 10-km long multiphase export lines.

The Campos Basin was discovered in 1974, through the Garoupa field and provided a new set of challenges. The water depth was 120 metres, the distance to shore was more than 100 km and the production rate was around seven times higher than in Brazil northeast platforms. For the first reservoirs in the Campos Basin Petrobras used available international technology. Fixed platforms were used in waters between 120 and 200 metres, considered deep at the time. Parallel to this development Petrobras developed and used the successful combination of wet christmas trees and a floating production system (FPS), as early production systems.

In 1984, the discovery of the Albacora field, followed shortly after by the Marlim and Barracuda fields took development into much greater water depths. To meet the new challenge, Petrobras conducted the first Procap (Deep Water Capability Programme), between 1986 and 1991. This was a six-year research and development programme with costs of over US$70mn, to develop technological capability to produce in waters as deep as 1,000 metres. Its success allowed the company to recently bring into production such fields at low costs and high safety standards.

In 1987, the 1,000 metres water depth barrier was broken with the discovery of the Marlim Sul field. This followed the discovery, at the end of 1996, of the giant Roncador field. These two fields extend across water depths of 800 to 2,600 metres.

The Campos Basin is currently the main petroleum province in Brazil. It is located offshore in Rio de Janeiro State, on the southeast of the country, and covers 100 sq km ranging from 50 to 3,400 metres water depth.

The first production system installed in this basin began production in 1977. In December 1997 the overall production system comprised 15 fixed platforms and 17 floating systems in 33 fields. Collectively they produced 680,000 b/d (71% of domestic oil production) and 12mn cm/d of gas (42% of Brazilian gas production) at the end of 1997.

Petrobras has been playing an important role in the research and development of deep-water technology. It recently brought into production its giant deep-water fields, Albacora, Marlim, Barracuda and Marlim Sul with wells in waters as deep as 1,709 metres. At the end of 1997, total Brazilian reserves of oil and gas equivalent reached 15bn barrels. Around 33% of the total is located in deep waters between 400 and 1,000 metres. The reserves located in depths over 1,000 metres, classified as ultra-deep waters, represent 39%. But in this case, it is first necessary to have the technology to allow production in such conditions. In short, over 70% of total Brazilian oil and gas equivalent reserves are in deep and ultra-deep waters.

According to Petrobras Exploration staff over 60% of the potential oil and gas discoveries will be in deep and ultra-deep waters. These figures show that Brazil's future oil production is strongly related to the development of offshore fields located over 400 metres water depths. Brazilian oil production reached 950,000 b/d in December 1997, but remained insufficient to meet the current Brazilian market demand of 1.7mn b/d.

In 2000, estimates indicate that Petrobras oil production will be able to reach 1.50mn b/d. In order to increase its domestic oil production, Petrobras must develop its deep-water fields. Estimates also indicate that around 65% of this oil production will come from deep waters in 2000. The volume of reserves to be exploited in this period will be twice the amount of the reserves already developed.

Petrobras' FPS experience

Petrobras' FPS experience is shown in **Table 1**. More than 260 subsea trees are already on the seabed, 2,800 km of flexible lines and umbilicals have been laid, 44 subsea manifolds and 15 FPSs are in operation. Significant increases are expected in the next three years, almost doubling the amount of equipment installed.

The installation of these 17 production systems and all the related equipment poses a significant challenge for a

Equipment	Installed (Dec '97)	Planned 1998–2000
Subsea Trees	261	215
Subsea Manifolds	44	12
Subsea Flexible Flowlines (km)	1,690	1,500
Control Bundles (km)	1,130	880
Floating Production Units	17	17
Monobuoys	10	2

Table 1: Equipment Demand Forecast

single oil company. Satisfied with the performance achieved with the FPSs, particularly in deep-water, Petrobras feels comfortable to install 17 more deep-water production systems to develop its oil fields in the next three years, as shown in **Table 2**.

The 17 systems will increase Brazilian production by more than 1mn b/d. The investments will be around US$7bn for the production development.

Deep-water challenges

A series of challenges and constraints had to be faced and overcome in order to produce the deep-water fields offshore Brazil. Although environmental conditions are milder, compared to the ones in the North Sea or the Gulf of Mexico specific problems had to be solved.

- **Step-by-step development:** The first rule was to get data in advance to avoid, or at least minimise, the 'surprises' during field development. The use of pilot systems and step-by-step development (modular) is highly recommended and is a default procedure at the company. By these means, future problems or adjustments in the development plans can be foreseen and its solutions can be provided for the next steps.

Some examples of the adoption of this strategy include: (a) the detection of the possibility of organic deposits in the flow lines in most of the deep-water fields and the development of solutions for the problem; (b) adjustment to the development plan of the Marlim field, without impairing the normal development plan, due to an increase in the production potential of the field; (c) suppression of the water injection wells due to a better knowledge of the Albacora reservoir during the first module development.

- **Ultra-deep water reservoir characteristics:** Ultra-deep water reservoirs with a large extension area and small effective thickness, presenting low temperature often varying along the reservoir extension, and with relatively high oil viscosity, pose a new set of challenges to the industry. These reservoirs' characteristics may result in lower recovery factors than desired. Since Petrobras is aware that these fields restrict the options for the application of conventional enhanced oil recovery (EOR) methods, either from an economic or technical point of view, they will require new approaches for the application of improved oil recovery (IOR) techniques.
- **Extended reach wells:** For deep-water projects, the wells are responsible for more than 50% of both capex and opex. In order to reduce that, the use of high productivity wells is a must. Non-conventional wells, such as horizontal, multi-lateral and extended reach wells – the latter in order to increase the attractiveness of dry completions – will play an important role in this scenario.
- **Low API oils:** The forecast for relatively heavy oil (15° API) production in ultra-deep water is another Petrobras concern. To ensure that the oil will flow through long-distance subsea lines, under low sea floor temperatures, new subsea fluid-flow technologies will be required, as well as innovation in the existing artificial lifting methods.
- **Subsea equipment innovation:** A complete new set of techniques, equipment and procedures were required to develop the deep-water fields. Flowlines, which are mainly flexible, had to be adapted to deeper waters. Thermal insulation among other enhancement, had to be added to the lines. Also light structures had to be used to reduce the loads of the risers in deep waters. The same happened to the christmas trees, manifolds, and services equipment.

One of the main challenges is the need to develop or re-engineer new subsea equipment required for the deep water. New subsea trees, flexible lines, lighter manifolds, reliable connection systems and boosting systems are required for the new environment.

- **Hydrate and organic deposition:** There are, in the company's deep-water projects, all the conditions required for organic deposits and hydrate formation in the flowlines where low temperatures, in both subsea floor and reservoirs, are predominant. That problem becomes a major concern as Petrobras moves to ultra-deep water.

New mooring systems

As the subsea lay-out in most fields is congested, mooring is also a major concern. A large mooring pattern, normally required for deep-water mooring, can impose heavy costs on the subsea equipment if flow lines and risers have to go around them to reach their connection points. Also, it may impose the use of dynamic positioning (DP) vessels as they would be the only ones capable of operating in the nearby area.

New mooring techniques must be developed so that the projects can optimise the subsea layouts and reduce the need of DP rigs for both development and maintenance phases, as they are scarce items in the market nowadays.

Costs are undoubtedly a major concern. The need for new technologies to allow production in deep waters must be linked with the need to keep costs at competitive levels. In order to overcome those barriers Petrobras is aware that, in some cases, it must pay the price of being a pioneer, mainly in the prototype phase of a new development. The company hopes to share those efforts with other operators who are also willing to foster new deep-water technology by sharing both the benefits and also the costs of the prototype tests.

Procap 2000

Ways to overcome the barriers encountered for deep-water production were addressed in the first Procap, which aimed to generate the technology to enable the production up to 1,000 metres, started back in 1986. In order to give continuity to the efforts of the first programme toward 2,000-metre water depth, Procap 2000 (Technological Innovation Program on Deep Water Exploitation Systems) was implemented in 1993. Those two programmes together with many other internal projects, Cooperation agreements, product and suppliers development had been carried out, extending the supply market and reducing costs.

A wide range of areas are covered by these development programmes from horizontal and highly deviated well technologies to subsea boosting systems.

Among the technologies required to produce in very deep waters, some can be highlighted as major contributors in reducing costs or in improving performance or even in enabling the field development.

- **SGN nitrogen generation system:** Organic deposits will continue to be a major problem due to paraffinic compounds present in the oil, which precipitate at the low temperatures found in deep waters, blocking the lines and reducing flow rates. Petrobras has developed a very effective thermo-chemical method, called SGN, to mitigate this problem. More than 80 successful cleaning operations have been carried out in the Campos Basin and this technology is available world-wide through a Petrobras licensee company.
- **ESPs in subsea wells:** Artificial lift will certainly be required for subsea wells, especially for low pressure reservoirs. Gas lift will not be able to cover a broad range of applications for long step-out distances. Electrical submersible pumps (ESPs) in subsea wells, seem to be more suitable for this task, although downhole gas separators still need to be improved.

The first prototype subsea ESP in the world has been successfully operating at the Petrobras Carapeba field in 90 metres water depth, since October 1994. Six partners were involved in this pioneer work and this cooperation was a key factor in its success.

- **Steel catenary riser:** Petrobras is planning to install at the end of this year the first steel catenary riser (SCR) on a semi-submersible, which is considered a strategic step for the oil industry. Once the practical feasibility of the SCR is proven, it will provide a cost-effective option to

Field	FPS	Type	Capacity (b/d)	Storage (barrels)	Start of Production	Water Depth (metres)	Number of Wells
Marlim	P-26 Iliad	Semi	100,000	—	Jan '98	990	17 – Prod 09 – Injec
Marlim	P-33 Henrique Dias	FPSO	50,000	2,000,000	Jun '98	710	06 – Prod 03 – Injec
Marlim	P-32 Cairu	FSO	—	2,000,000	Mar '98	160	—
Marlim	P-35 José Bonifácio	FPSO	100,000	2,000,000	Sept '98	860	17 – Prod 05 – Injec
Marlim	P-37 Stena Continent	FPSO	150,000	—	Jul '99	905	20 – Prod 15 – Injec
Voador	P-27 Penrod 71	Semi	50,000	—	Apr '98	540	07 – Prod 03 – Injec
Albacora	P-31 Vidal de Negreiros	FPSO	100,000	2,000,000	Feb '98	330	28 – Prod 06 – Injec
Barracuda	P-41	TLWP or Spar	—	—	Aug 2000	765	13 – Prod 11 – Injec
Barracuda	P-43	FPSO	150,000	1,800,000	Aug 2000	785	04 – Prod 05 – Injec
Barracuda	P-42	TLWP or Spar	—	—	Sept 2000	870	11 – Prod 07 – Injec
Barracuda	P-44	FPSO	150,000	1,800,000	Sept 2000	840	03 – Prod 02 – Injec
Marlim Sul	P-40 DB-100	Semi	150,000	—	Sept '99	1,080	13 – Prod 11 – Injec
Marlim Sul	P-38 Eastern Power	FSO	—	1,800,000	Sept '99	1,020	—
Roncador	P-36 Spirit of Columbus	Semi	180,000	—	Apr '99	1,360	19 – Prod 07 – Injec
Roncador	P-47 Eastern Strength	FSO	—	1,800,000	Apr '99	815	—
Salema/ Bijupirá	P-45 Jequitibá	FPSO	55,000	850,000	Jun 2000	670	16 – Prod 04 – Injec
Leste de Marimbá	P-21	Semi	25,000	—	Apr '98	700	03 – Prod
Total			**1,360,000**	**16,050,000**			

Table 2: Floating Production Units Under Development

export or import hydrocarbons, either to or from floating production units. It will be an alternative to the expensive flexible pipes and based on that, it is possible to foresee a direct and indirect cost reduction.

The main reason for full-scale comprehensive monitoring of an SCR prototype is to better understand the real behaviour of such an innovative device. Data gathered will make it possible to confirm the analytical modelling and, therefore, calibrate the design parameters.

The SCR technology has not yet accumulated large industry experience. In order to evolve SCR technology a little faster, through its application on a moored floating unit, Petrobras is developing this project.

- **Taut leg mooring:** The taut leg mooring system will replace conventional mooring systems for the majority of the future floating systems to be installed. Its main advantages are a sharp reduction of the mooring radius, as can be seen from the Marlim field case, increased payload and lower offset. In addition, the use of the taut leg concept is considered very important for the development of the deep-water fields, since it reduces the need for DP rigs, and allows the optimisation of the subsea layout.
- **Boosting systems:** The attractiveness of subsea boosting has been confirmed in the recent screening study conducted by the company for the three giant deep-water fields. The main idea is to install these boosters close to the wellheads to transport the produced fluids to an FPS.

Petrobras has set up a test site at Atalaia and is investing in three different types of technology: ESPs in subsea wells, multiphase pumping and subsea separation. Petrobras joined the VASPS project and continues to develop the Pekoboost, the patent gas-driven system. Now in its fifth year of ongoing work, the deep-water research programme, Procap 2000, has reached the prototype phase, mainly for the projects related to the boosting systems. Petrobras is confident that these new technologies can add value to the deep-water developments by cutting costs per barrel produced by up to 30%.

- **ESPs in subsea wells:** Demonstrating the company's confidence in the technology, the next step in the subsea ESP project will be the installation of a pump in the well RJS-477, located in 1,100 metres water depth, in the Albacora Leste field. It will use a guidelineless horizontal tree, special 9-km electrical cable, and a subsea transformer. Production is expected in April 1998.

The Petrobras vision of an 'ultra'-deep water production system is one where there will be a few high productivity subsea horizontal wells, connected to subsea manifolds, and then to subsea boosting systems. The wells may be equipped with an ESP. From the boosters the production will be sent to an FPS, located in 1,000 to 2,000 metres water depth range, through flexible or steel pipes. Petrobras expects the TLP and the Spar concepts will have an important role in future deep-water production projects. For the export of the produced oil the company is considering the use of either shuttle tanker or pipeline, while the gas phase is compressed either for reinjection or to be sent to shore via steel pipeline.

The true challenge in deep water is using technology to make the development economically sound. But, if adequate planning and risk management is used, even with the presently available technologies the challenges can be successfully faced. A phased (step by step) development strategy, where risks and capital exposure are minimised, is an interesting approach that also allows cash flow to finance the next phases.

This has been the Petrobras approach over recent years, and the company believes that it can be successfully applied worldwide.

Total management commitment needed for safe operations

Offshore safety continues to tax the minds of senior management. Throughout the industry, quietly and steadily, actions are being taken, which may not hit the headlines, but which are illustrative of an ever-increasing determination towards a better and safer working environment. *Neil Potter* looks at the current scene.

The technological advances in the industry in recent years have doubtless played a role in improved safety statistics. It must be said, of course, that this is partly due to the fact that they have led to fewer people being employed offshore.

But, increasingly, has come the understanding that safety involves people – not only the workforce but also senior management. There is a realisation that probably the most hazardous aspect of safety is people – that is to say, they are often a danger to themselves and their colleagues.

Equally, safety demands leadership. Management commitment is a prerequisite for workforce involvement. More and more companies have adopted the philosophy of Du Pont, regarded as a world leader in this field: 'You get the level of safety that you demonstrate you want'.

Last autumn saw the launch of the cross-industry safety leadership forum, which introduced the Step Change in Safety programme.

The founder members of this cooperative initiative were UK Offshore Operators Association (UKOOA), International Association of Offshore Drilling Contractors (IAODC), and Offshore Contractors Association (OCA) with the support of the Health and Safety Executive (HSE). Since then the International Marine Contractors Association (IMCA) and the TUC have joined.

The aims include:

- a commitment to deliver a 50% improvement in the industry's safety performance over the next three years;
- for senior management in companies and contractors to establish their own safety performance contracts, to demonstrate visibly their personal concern with safety as an equal to business performance; and
- to work together to improve sharing safety information.

John Wils, Director of UKOOA in Aberdeen, says: 'We are making continual progress. A high level steering committee has been established under the Chairmanship of George Watkins of Conoco.

All senior managers have now completed their personal safety contracts. We are now in the process of working out the deliverables. Task forces have been established for each of the initiatives and are working hard to achieve their objects'.

Universal responsibility

Close cooperation between all those involved is a key feature. The OCA commissioned a report from the Robert Gordon University in November 1997 to look at the workers' attitudes to safety and the management of risk offshore. This found that around 80% of the contractors' workforce were happy with the safety measures on installations.

Syd Fudge, OCA Chairman, said he believed that much more could still be achieved by changing attitudes towards safety. 'We must ensure that the workforce takes ownership of safety by including it in the decision-making process'. The OCA is taking the report's findings to assist in achieving some of the objectives agreed by Step Change.

Discussion is underway to identify the best method of reporting accident statistics, where definitions require more clarity. The 'three day' injuries and dangerous occurrences previously used are now considered unsatisfactory. The HSE considers data should be presented in the form of incidence rates per 100,000 employees. BP, for example, considers the Lost Time Injury Frequency (LTIF) inadequate. It is now using the Incident Severity Index, which reflects the average potential severity of incidents on all its installations.

Key campaigners

One of the major players in the safety campaign is Shell Expro, whose Heinz Rothermund was last year's president of UKOOA and played (as he continues to do) a leading role in the campaign. Shell has committed to fully support the initiative, including the adoption of any agreed pan-industry systems or activities wherever practicable. It has set up a structure for its programme – Enhanced Expro Leadership Theme. There is a Step Change coordination group, which will meet every two months. Three major themes have been identified and will be supported by a team of representative discipline and line staff. The offshore installation managers' (OIM) focus group for Step Change will be represented on all Theme teams.

These consist of enhanced workforce involvement and safety culture; well engineering safety and workplace hazard management.

Shell would be the first to admit that it learned a great deal about safety management, safety culture and the attitude of the workforce during the execution of the overall Brent Field redevelopment project between 1991 and 1997, which cost £1.2bn. Offshore work began in mid-1993 on Bravo followed by Charlie, which was completed in November 1996, and then Delta where work lasted from April to 21 September 1997.

There is no doubt that it received a shock in December 1986 when it got the report it had commissioned together with Wood Group Engineering from Robert Gordon University. A cross-section of workers, including engineers and supervisors, on Brent Charlie were highly critical of management over safety issues. In general they appeared to lack belief in management's commitment to safety.

Key findings were integrated successfully into an updated platform safety action group with a significant improvement in safety performance.

The lessons learned on Charlie were

taken on board for work on Brent Delta.

Tony Brown, Delta Project Manager says: 'The main point is that safety management is about people and nothing else. It is about avoiding grief to workers and their families. You rarely hear of foremen getting hurt; it is invariably the guy with the tools.'

Time and money investment

On the Delta project 25–40 % of management time was spent on safety. There was a constant attention to safety in everything that was done. The platform was divided into five areas with an engineer responsible for construction, cost, progress and safety.

The safety profile was raised by introducing an outstanding safety contribution and reward (OSCAR) suggestion scheme and more than 300 ideas were put forward. There were monetary payments for gold, silver and bronze suggestions. Safety management on Delta was based on five Cs – commitment, communication, cooperation, competence and consistency.

'We put an enormous amount of effort into managing safety and this produced some very positive results, with those working on the project really getting personally involved in managing their own and their colleagues' safety'. Training was given to safety representatives in presentation skills, computer skills and communication skills.

Every effort was made to keep the same teams working together for as long as practical. A strong focus was placed on minor injuries and their prevention.

Some £40,000 was invested in shore training for management, supervisors and safety representatives before any work began offshore. Indeed, the thoroughness with which safety issues was approached prior to the actual work commencing is illustrated by the staff involvement in the first three months of 1997. There were safety representative workshops and seminars; area engineers workshops; management familiarisation and training courses; and supervisors training courses.

Agreement was reached with the safety representatives on discipline rules – violations of which would result in a verbal warning and a written warning. A safety newsletter was sent to the home addresses of the entire workforce and a handbook was issued. Tony Brown, prepared a safety video that was shown at the Sumburgh heliport every month. ('This also meant that everyone knew me and who I was,' said Brown. 'Everytime I went on the platform, people would stop me and talk about safety'). Hazard analyses were carried out on jobs to be done before the offshore work started; and by March the Safety Charter had been drawn up.

Workforce awareness

The HSE is well aware, as is the permanent workforce on an installation that a key danger point is when large numbers of new contractors' personnel arrive on a platform. On Brent Delta the permanent workforce of 250 was supplemented by up to 900 extra personnel at any one time. With the two-weeks on/two-weeks off system, this meant an extra 1,800 people, many of whom would not be aware of Shell's safety culture.

'One of the major steps we took', says Brown, 'was to improve the induction process. The OIM and the safety representatives met every newcomer on the platform and explained what we were trying to achieve with regard to safety. They were asked to sign a personal safety charter under which they took formal responsibility for safety. This was signed by me and confirmed by the safety representative. We had no refusals'.

The Brent Delta Safety Charter pointed out that one-third of all accidents involves slips, trips and falls. It set out the management commitment to inform, involve and to respond promptly to all suggestions.

The individual's commitment was 'to stay aware of changes as conditions will be changing rapidly on the project; to stay alert; to take great care when lifting, walking or climbing; to obey all signs and barriers; to only use tools that are suitable for the job and if you see anyone doing anything which you feel is putting them (or you) at risk, talk to them about it'.

Attitudes to safety

It is significant that two of the key issues being addressed by Step Change task forces are: to develop guidelines to improve the induction process for new employees, led by BP, and to build on the elements already in place for a common induction process agreed for all offshore workforce, led by Shell.

For Brent Delta, Aberdeen University carried out a study of the attitudes to safety of 12% of the workforce. This showed that there was a good safety atmosphere – 85% considered that safety is taken seriously and was not just a domestic exercise; 65% said they trusted their supervisors. The workers believed that they themselves were responsible for their own safety; the safety representatives were seen as being actively engaged in safety management; managers were open and honest.

Seventy per cent complained that the rules and policies were constantly changing. The safety representatives said this was simply not true. 'But', says Brown, 'there were aspects which emerged which should be, and are being, addressed. These indicate that there are still some outstanding areas where we have to take steps for improvement. These indicate that there is still a lack of communication, as we clearly had not got the messages across satisfactorily'.

For Brent Delta, in statistical terms, LTIF – lost time injuries per million manhours – was 1.7 in 1996. For 1997 this had been reduced to one. The Total Recordable Case Frequency (TRCF) – total recordable cases per million manhours (which includes LTIF) – in 1996 was 7.8 with the 1997 figure down to four.

Recording of incidents

There has been considerable discussion within the industry on the best way to record safety statistics. For many years the three-day injury was the criterion. But it was open to misinterpretation. In April 1996 the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations (RIDDOR) came into force. One of the task groups in Step Change is developing standard incident potential matrix for use with RIDDOR reporting.

The HSE considers that data presented in the form of incidence rates per 100,000 employees provides the best basis for comparison and trend analysis with other sectors. But the estimates of people working offshore are supplied by the Inland Revenue. UKOOA and the Inland Revenue, together with IAODC, the British Rig Owners' Association (BROA) and OCA, have been working together to improve the accuracy of the estimates as well as breaking down the numbers into different activities.

Iceberg alert

Whatever statistical basis is devised, there is no room for complacency – constant vigilance, by both management and workforce, whether operator or contractor, is essential. To sum up, in the words of Greg Bourne of BP, who was Chairman of the group which initiated Step Change before being sent to Venezuela: 'As we become more successful in eliminating accidents, we need to concentrate on the iceberg which lurks below the waterline, waiting to wreck our achievements at any time'.

The crucial role of IT in global oil trading

Information technology (IT) plays an increasingly vital part in trading and risk management as well as supporting the day-to-day operations of any oil company. Without the right tools, risk models and back-office processing systems it is unlikely that trading could take place at the same level of both volume and complexity, reports *David Brown*, Consultant in CMG's Oil Division.

There are three main reasons for trading in the oil markets. The first is supply: when oil companies are producing and selling crude oil to refineries, or finished products to industrial customers such as airlines.

The second is when organisations are hedging their risks. A tour operator, for example, wants to avoid buying fuel at a price that is higher than it had expected when it sold holidays to customers. This kind of organisation needs to be able to predict what the price of fuel will be so that it can lock in its profit margins.

The third reason is for speculation: buying and selling oil, and oil derivatives (cash contracts based on the price of oil) with the single-minded objective of making a profit. Two types of organisation are involved in speculation – some of the oil companies themselves, and third-party brokers, banks and trading houses.

Oil derivatives are traded on three main exchanges: the International Petroleum Exchange (IPE), the New York Mercantile Exchange (NYMEX) and the Singapore Mercantile Exchange (SIMEX). There are also so-called 'over-the-counter' trades where one company deals direct with another.

Oil trading is a vital part of the industry, because without speculation it would be impossible to hedge risks. Without being able to hedge risks, customers and suppliers would be unable to plan their business. Profits would always be dependent on unpredictable future oil prices.

Yet despite its growing importance in the oil industry, there are clearly challenges involved in both trading and risk management. The first is credit management – particularly when carrying out over-the-counter trades – where payment is not always guaranteed. Traders also need to be able to manage the credit position of the whole organisation by knowing the up-to-date credit position of any counter party before they close a deal.

The second challenge is communication, and the ability to react quickly to information. As well as knowing what the current price of oil is, traders need up-to-date market knowledge. They need to know what factors affect prices, including political events and other global news. Markets react quickly to news, so traders must always be at least as well informed as the party with whom they are trading.

Just as importantly, traders need tools that help them to sift through data sources so that they have just the facts and figures that they need, not information overload.

Those two elements become even more important as the trading picture gets even more complex. One dynamic in the oil trading business is the growth of technical trading, where specialists track historical price movements and trends, using this data to predict future price movements. These predictions are used to trade into positions which have a high probability of being profitable.

IT dependent

More than any other style of trading, technical trading depends heavily on IT, and is indeed driven by the growing capability of systems to analyse data quickly and accurately.

Massive numbers of transactions may be done every day, often for deals worth millions of dollars. If a single figure is wrong, then a huge amount of money can be wiped off the bottom line.

So which processes within trading are supported by IT, and how are systems developing now to cope with the growing complexity of the international oil markets?

The first group of processes supported by IT are within the front-office function of the trading organisation. This includes all of the processes which are carried out before the deal is done, including the delivery of news and market information to traders, and messaging between traders so that information and trading positions can easily be shared.

Front-office processes also include price analysis and capture – what the trends are in pricing, and what the market is doing. For example, option prices fluctuate relative to the underlying price of a product, and computer-based analysis tools are required to calculate the market value of an option. This is based on a number of different variables: the current market price, the time from the present to the expiry date, current market volatility, and exchange rates.

Of all of the front-office processes, accurate price capture and analysis is perhaps the most crucial. But because prices fluctuate so much, traders rely on IT to help them to come to a decision about which price to buy or sell at. As every deal is done, it becomes known to the market via agencies (such as Platts) that monitor prices and publish market prices 24 hours later.

This transparency in prices and deals can only happen if organisations have the right communications technology in place to support information delivery to the desktop PC or workstation. It is also clear that front-office technology must be totally reliable and effectively supported. If a trader is unable to access the right information, or analyse prices, or see his credit position, then he may quite simply be unable to trade.

Just as important is the back-office function, which includes all of the processes to do with accounting and settlement of deals. While front-office applications tend to be based on leading edge PCs or workstations linked by high performance networks, back-office systems are more likely to be based on more traditional mainframe computers which are best for handling large volumes of transactions.

Back-office processes include the automatic generation of documents, such as contracts, invoices and delivery documentation. The back office system will also manage the administration of futures and options, settlement of deals with the exchanges, and daily reconciliation of the organisation's position.

Middle office

Everything else in between the front office and back office is handled by the middle office, which may be thought of as the processes of managing an organisation's current portfolio of trades. It includes risk management – which is the process of assessing the potential loss that may result from market price movements – third parties' failure to perform, and other factors outside the management's control.

One of the biggest issues for the middle office is deal capture. In order to manage risk and the portfolio accurately, managers need a great deal of information about each trade. Yet the speed at which traders operate means that they tend to capture the minimum of information, and record it in a form of shorthand.

Some organisations have two people entering this information – often from handwritten notes – into the system at once, so that any mistakes or discrepancies in recording can be identified early on and corrected. New techniques, such as touchscreens or voice-based data entry, may help to solve this issue in the future.

New IT tools are also developing to help support a more complex view of risk management. In the past, risk management meant looking at a relatively low level of factors, such as net and gross volumetric exposure. Today, managers are following the lead of financial risk managers, and taking many more variables into account, such as the probability of price change over a particular period of time.

Because working with the raw data on price movement over time would be far too time-consuming even for today's systems, organisations are developing tools that analyse a higher level of information – the relationship between movements, rather than the numbers themselves.

The role of companies like CMG is to build the applications that oil companies need to maintain and analyse a central database of price and portfolio information, as well as to support reporting and deal capture. We see developments in the future following a number of different routes, including the need to make information available to global organisations.

The difficulty here is ensuring that the data shared by offices in different countries is always up to date. Despite vast improvements in the speed and quality of data communication, it is still relatively time-consuming to send resources such as spreadsheets around the world.

However, it could be possible in the future to adopt the same techniques used for the Internet to open up information via private internal networks – called intranets – to global users. There are clearly still performance and security issues to work through before this can become a reality.

So far, IT has helped organisations trading oil and oil derivatives to introduce more effective, automated processes across the front and back offices. It would be literally impossible for trades to happen if traders could not access price information, global news and the company's current position. And although the organisation would not have to close down if back-office or middle-office systems failed, documentation, settlement and reconciliation depend heavily on automated processes.

Next steps

The next great steps forward will come from the development of more and more complex and accurate risk modelling tools, which will allow organisations to examine historical information and current trend in ever finer detail, with more variables than ever before.

So although experience and knowledge of the oil industry will always be important in trading, IT will continue to develop in order to take as much guesswork and risk out of the process as possible. And the organisations which take full advantage of the emerging IT solutions will be the ones which succeed in the future.

CMG plc is a leading European Information Technology services group. Established in 1964, CMG now operates in more than 30 countries from its bases in the UK, the Netherlands and Germany. The Group is listed on the London and Amsterdam Stock Exchanges.

CMG supplies systems development, management consultancy and advanced technology services in the finance, transport, trade and industry, energy, telecommunications and public sectors. The Group also provides managed information processing services, including payroll and personnel.

Market liberalisation leads to closer integration

For the most part, liberalisation of the gas industries of the US and Canada is producing a more integrated North American gas market. Indications of this are evident in the plans for greatly increased Canadian gas export pipeline capacity, the involvement of Canadian companies in wholesale US gas marketing, development of similar types of market centres and hedging instruments, and changes in the length and pricing of contractual obligations, writes *Judith Gurney*.

The Canadian share of the US gas market in 1997 is estimated at 13.7%, a figure which reflects the export of 2.9tn cf of gas, more than half of Canada's total production. Exports are focused on four US regional markets. In 1997, some 36% went to the midwest, 24% to the west, 23% to the northeast and 17% to the northwest. Pipelines for the midwest cross the border in Michigan, Minnesota, Montana and North Dakota; those for the west cross at the single entry point of Eastport, Idaho, and almost all is marketed in California. Five lines to the northwest, of which three are user-dedicated, enter at Sumas, Washington, and lines for the northeast enter New York and Vermont. Export prices are set in the regional market where the gas is sold, with the highest prices currently realised in the northeast. Regions differ in their gas use with industrial sector demand dominating in the midwest and residential sector demand highest in the northeast.

Canadian shippers would like to capture more of the midwest and northeast gas markets where they expect increased future demand for gas by electricity generators. They have been prevented from doing so in recent years by lack of export pipeline capacity, with capacity utilisation on existing lines averaging 87%, and, in some cases, 100%.

Alliance Group proposal

In the early 1990s, a number of Canadian producers and marketers in Alberta – where more than 84% of Canadian gas is produced – initiated a Northern Area Transportation Study to address the problem of insufficient export pipeline capacity, citing the monopoly control exercised by TransCanada, owner of the single transcontinental pipeline transporting gas from the Western Canadian Sedimentary Basin to the east.

They were also concerned with the monopoly control exercised within Alberta by Nova, owner of the province's gas gathering and distribution system. Some members of this group felt that Nova's 'postage stamp' pricing, whereby producers paid the same rate to ship their gas, regardless of how far that gas had to travel, created inequities.

Others believed that Nova was opposing an increase in exports in order to ensure a supply of low-priced gas within the province to provide feedstocks for its significant investments in Alberta's petrochemical industry.

In 1994, these producers formed the Alliance Pipeline Group and proposed to construct, at a cost of C$4.1bn (US$2.9bn), a gas export pipeline beginning in northeastern British Columbia, running 1,000 miles through Alberta, crossing the US border in Saskatchewan, and then proceeding 900 miles through the US to a market centre near Chicago, Illinois, where it would interconnect with the US pipeline grid. Initial throughput volume of this 36-inch pipeline would be 1.325bn cf/d and a natural gas liquids extraction plant would be built at the pipeline terminus.

The Alliance Group has received regulatory approval for its construction plans in the US sector from the US Federal Energy Regulatory Commission (FERC), subject to an approved Environmental Impact Statement. It has filed for regulatory approval with the Canadian National Energy Board (NEB) where public hearings began early in January. Canadian industry analysts currently give the project a better than 90% chance of NEB approval, and the Alliance Group hopes to bring the project on stream by mid-2000.

Equity shares in the Alliance Group, whose charter members included 22 gas producers, have changed hands since 1994, with US companies becoming more involved. In March 1998, the major Canadian companies with equity in the project included IPL Energy with a 21.4% share, Westcoast Energy with 18.5%, and Fort Chicago Energy Partners with 26%. The major US companies included Coastal Corporation with 10.4%, Duke Energy with 9.8%, Unocal with 9.1%, and Mapco (Williams) 4.8%. Gas producers have contracted for 65% of the pipelines capacity with the rest held by marketers and local distribution companies.

TransCanada/Nova response

TransCanada also had plans in the mid-1990s to expand export pipeline capacity but these have undergone several changes, presumably partially in response to the Alliance pipeline pro-

Natural gas Supply and Disposition 1996 (bn cm)

posal. Originally it planned a large-scale general expansion entitled 'Nexus'; this project was replaced by a plan to build a 'TransVoyageur' pipeline from Empress, Alberta, to Emerson, Manitoba. In January, TransCanada announced that it was dropping the TransVoyageur plan in favour of a 1.4bn cf/d expansion of its main pipeline.

TransCanada's involvement in pipeline projects within the US to handle Canadian gas exports, however, has not changed. These include a 40% interest, with Northern States Power and Nicor, parent of Northern Illinois Gas, in a proposed 1.2bn cf/d 'Viking Voyageur' pipeline to take gas from Emerson, Manitoba, through Minnesota and Wisconsin to Chicago. TransCanada is also involved, with IPL Energy, Columbia Gas and MCN Energy, in a proposed 343-mile 'Vector' pipeline to carry Canadian gas from the Viking Voyageur terminus to a market hub in Dawn, Ontario, and a 381-mile 'Millennium line', proposed by Columbia Gas, Westcoast, MCN Energy, CMS Energy, and IPL, to move gas from Dawn to New York.

In late 1997, talks regarding an agreement between the Alliance Group and Nova failed, and Nova turned its attention elsewhere. On 26 January 1995, in what many saw as a direct response to Alliance Pipeline, TransCanada and Nova announced their intention to merge through a 'pooling of interests', connecting Nova's Alberta gas gathering and transmission system with TransCanada's transcontinental line to form a 'seamless' pipeline service from Alberta to eastern Canada and the US. The merged company, which will spin off Nova's $3bn petrochemical division, is expected to receive the approval of the necessary government regulatory bodies.

Other export projects

The Maritimes & Northeast Pipeline, which has received the necessary regulatory approvals to proceed, will bring gas from the Sable Island field, offshore eastern Canada, to the northeastern states of Maine, New Hampshire and Massachusetts. Sable Island reserves are estimated at 3tn cf and these will be produced by a partnership of Mobil, Shell, Imperial Oil (Exxon) and government-owned Nova Scotia Resources. Partners in the pipeline company include Duke Energy, Mobil and Westcoast Energy. Foothills Pipelines, in which TransCanada, Westcoast and Nova have equity, and the Northern Border line, in which Enron, Duke

	Production	Gas	Imports*
1990	514.2	540.3	26.1
1991	510.4	549.0	38.6
1992	514.5	563.7	49.2
1993	520.4	583.2	62.8
1994	541.8	596.1	54.3
1995	534.9	620.6	85.7
1996	546.9	632.4	85.5

**Implied imports not all from Canada*

Source: BP Statistical Review 1997 *plus interpretation by* Petroleum Review

US gas statistics 1990–1996 (bn cm)

Energy, TransCanada, and Williams have equity, has also received approval for expansion plans to bring more Canadian gas from Saskatchewan to Chicago.

Market operations

When US interstate pipelines were required, in the early 1990s, to relinquish their merchant role as a result of government liberalisation policies, a host of marketing companies appeared to take over the wholesale buying and selling of gas. Within a few years, many of these companies had disappeared or had been bought up by others, and large companies dominated the wholesale marketing of gas in the US and the trading of pipeline capacity and storage. Several of the top ten marketing companies have Canadian partners. Nova, for instance, holds a 25% interest in NGC, formerly Natural Gas Clearinghouse, which ranked first in the list of marketing companies handling the greatest volume of gas sales in 1996. Westcoast Energy of Vancouver, British Columbia, is a partner, with Coastal Corporation of Houston, Texas, in Engage Energy, which ranked fourth. Shell Canada was joint owner, with Tejas (subsequently acquired by US Shell Oil) of Coral Energy Resources, which ranked seventh, and TransCanada Gas Services, on its own, ranked eighth.

Market centres and hubs have become the focus of gas marketing operations in both countries, with 38 centres, of which seven are in Canada, providing pipeline interconnections as well as gas transfer, parking, loaning, storage and other services to shippers. Many offer electronic trading through systems developed by Streamline and Quick Trade in the US and the Natural Gas Exchange in Canada.

Futures markets

Increased spot market activity following decontrol of wellhead gas prices has led US and Canadian market participants to turn to hedging instruments, both over-the-counter arrangements and futures contracts, to protect themselves against risks arising from price variations.

Traders have a choice of four delivery sites for gas futures contracts. There are two sites for New York Mercantile Exchange (NYMEX) contracts, one for delivery at the Henry Hub in Louisiana and the other for delivery at the Permian Basin Pool in west Texas, and one site for Kansas City Board of Trade (KCBT) contracts for delivery at the Waha Hub in west Texas.

In 1997, NYMEX opened a Canadian delivery site in Alberta. These delivery points were chosen for their high volume of trading activity and their high degree of volatility in price changes.

	Production	Consumption	Expts*
1990	99.3	61.8	37.5
1991	105.4	63.0	42.4
1992	116.1	66.8	49.3
1993	125.5	68.4	57.1
1994	135.9	70.8	65.1
1995	148.2	70.9	77.3
1996	153.0	73.7	79.3

**implied*

Source: BP Statistical Review 1997 *and* Petroleum Review

Canadian gas statistics 1990–1996 (bn cm)

Contracts

When US interstate pipelines ceased to be gas merchants, their large-volume, long-term contract arrangements for western Canadian gas supplies were terminated and new contracts were drawn up by marketers and local distribution companies. These were generally for a shorter term, and indexed to US or Alberta spot market prices or to NYMEX futures contracts prices.

When the majority of current contracts come up for renewal around the turn of the century, it is anticipated that they will be replaced with shorter-term, more flexible arrangements for smaller volumes. The current 'unbundling' of US local distribution companies services in many US states is expected to lower the supply needs of these buyers.

Price divergence

Although the US and Canadian gas markets have come a long way towards forming an integrated market, there is a major obstacle towards further moves in this direction. This is the significant difference in gas prices in the western and eastern regions of the US which reflects a major discrepancy in the supply and demand balance of what has become, in effect, two separate gas markets. Recognition of this fact was a major reason for the establishment of futures contracts with deliveries in both Louisiana and west Texas. In 1996, the Canadian NEB estimated the extent of this discrepancy in terms of a gas supply of 9.0tn cf and demand of 5.3tn cf in the western region, compared with a supply of 15.6tn cf, and demand of 19.5tn cf in the eastern region. Its study of spot prices showed that price divergence had increased over a period of three years and noted the difficulty of hedging risk in contracts involving both regions.

It remains to be seen if plans for the construction of new pipelines and pipeline expansions linking Alberta with Chicago, and taking gas from there to eastern markets, are realised, and if these will eliminate, or at least lessen, the east-west price divide and bring more integration to the North American gas market.

BS 4275 – new standards in new environments

A radically revised approach to evaluating the performance of Respiratory Protection Equipment (RPE) combined with efforts to harmonise European standards has led to a wholesale revision of BS 4275. Introduced in December 1997, the standard entitled 'Guide to Implementing an Effective Respiratory Protective Device Programme', replaces the previous guidelines from 1974, writes *Keith Roddan*, 3M Marketing Manager, Development Manager & Former Chairman of British Standards Committee PH/4/1.

A workplace protection factor study: measuring protection factors in the real world

Unlike its predecessor the new standard takes a total systems approach to the choice and use of RPE and will provide invaluable help to safety professionals in companies throughout the UK. But why the need for a revised standard with a significantly different method of calculating performance levels?

Changes to BS 4275 follow a great deal of research as well as a prolonged international debate about the levels of protection afforded by respiratory protective devices in the actual workplace. Since the original BS 4275 was published nearly a quarter of a century ago new equipment and performance levels have become the norm. The standard formerly covered only the selection, use and maintenance of RPE. The new revision covers all aspects of a respiratory protective device programme including auditing, training and fit testing.

The initial impetus for change arose from a desire to harmonise European standards to protect those working in hazardous environments and exposed to airborne toxins. However, when work began on a Euro-version of BS 4275 great difficulties arose over the protection levels to be included.

With no overall agreement the standard was never formally adopted and wound up on the shelf as Committee Report CR 529 at the end of 1989.

When the European work stopped, the UK national committee reconvened in 1993 to work on an updated British Standard given that the contents of the original were now effectively obsolete.

Academic research also became a driving force in re-evaluating how effective RPE was in a workplace environment and how protection factors should be assigned. The 1974 standard introduced Nominal Protection Factors (NPFs) for all types of RPE. These were based on 30-minute tests under laboratory conditions to measure leakage into the face piece. For example, full-face pieces had to have a leakage of less than 0.1% of the test dust and the level inside the mask had therefore to be a thousand times lower than outside it. This is where the nominal protection factor of 1,000 for full-face pieces came from.

However, various workplace studies began to indicate that there were wide discrepancies between the performance and protection levels of RPE in laboratories and in the work environment because of a range of variable factors such as the hazardous materials involved and the levels of training and motivation of the wearer.

The revised standard bases its protection levels on evidence gathered not in the laboratory but on the factory floor. NPFs have been replaced by Assigned Protection Factors (APFs) in which 95% of wearers in the workplace can realistically be expected to attain that level of protection, given adequate training and supervision.

Yet in most cases APFs are dramatically lower than NPFs. For example a full-face piece with a P3 filter has an NPF of 1,000 but has an APF of only 40! Understandably this has prompted widespread, although unjustified, concern that standards have in fact been reduced.

Given the radical changes reputable manufacturers of RPE such as 3M have set up special helplines to give companies expert advice on best practice in setting up an RPE programme covering the selection of suitable devices and their limitations, use, storage and maintenance, training of wearers as well as supervision and administration.

The new standard, although not enforceable by law, puts the onus on employers to ensure that their workforce is educated in the hazards from airborne substances present in their working environment and that there is a comprehensive RPE programme in place.

Looking to the future, active steps are being taken to report back to Europe in the hope of eventually reaching a harmonised standard. It is a gradual process but if there is the commitment from individual nations, agreement should be reached in the end.

Copies of the new standard are available from the British Standards Institute (BSI, Customer Services, Sales Department, 389 Chiswick High Road, London, W4 4AL, UK. Tel: +44 (0)181 996 7000; Fax: +44 (0)181 996 7001) or, alternatively, 3M is offering a free fact sheet which can be obtained by calling the 3M Health & Safety helpline on 0800 212 490.

Boosting subsea wells

After many years' research and development (R&D), subsea multiphase pumps are being used in an increasing number of commercial applications to boost flow from unproductive reservoirs and to extend tie-back distances from subsea satellites. Norway claims the first commercial application, but subsea multiphase pumps are now being deployed in Chinese, British and West African waters, writes *Jeff Crook*.

Multiphase pumps are designed to handle the natural flow from an oil well before the products have been processed. By the early 1990s, a number of multiphase pumps were providing reliable service on oil platforms and from that time onwards the R&D challenge was to adapt these designs for subsea operation. One important milestone was the trial of a subsea multiphase pump by Agip in the Prezioso field offshore Sicily in 1994.

The first commercial subsea multiphase pump installation was in Shell Norske's Draugen field and came onstream in November 1994. Oil production from the Rogn South subsea satellite was boosted by 4,500 b/d by this system. The multiphase pump was driven by a hydraulic turbine fed from the water injection manifold. A somewhat similar arrangement will be used for boosting production from the Machar subsea wells in BP's Eastern Trough Area Project (ETAP).

Electrical driven multiphase pumps were developed following the success of the Draugen project and the first commercial versions were installed in the Lufeng 22/1 field, in the South China Sea towards the end of last year (see opposite). Orders have also been received for two electrically driven subsea multiphase pumps for the Topacio field offshore Equatorial Guinea.

The Topacio field lies in water 600 metres deep and is being developed by a subsea production manifold tied-back to the FPSO *Zafiro Producer* which is moored in shallow water. The two 900 kW electrically driven booster pumps have been integrated into the Kongsberg HOST (Hinged Over Subsea Template).

Draugen

The Draugen subsea multiphase pumping system was developed by Framo Engineering A/S under the Shell Multiphase Boosting Station (SMUBS) project. This project was started in 1987 with support from A/S Norske Shell and Shell Internationale Petroleum Maatschappij BV. The SMUBS module consisted of a Poseidon helico-axial pump driven by a hydraulic turbine together with a flow mixing unit. The flow mixing unit, technically known as a 'static flow homogeniser', was installed immediately upstream of the pump to smooth out slug flow conditions that could arise in the undulating subsea pipeline.

The subsea module was installed in 270 metres on a water injection manifold, 6 km from the Draugen platform, to boost flow from satellite wells located on Rogn South field located a further 3 km from the injection manifold.

The rotating elements of the pump and turbine are contained in a retrievable cartridge which is encapsulated by a receiver barrel. The retrievable cartridge, containing all components which can sustain wear, can be withdrawn to the surface by means of a remote pump module running tool. The receiver barrel is permanently connected into the structure of the subsea manifold. Framo says that installation of the SMUBS unit was carried out in less than 12 hours (exclusive of mobilisation and demobilisation) by means of a pump module running tool from a diving support vessel (DSV).

No mechanical seals are used in the design and all bearings are lubricated by the turbine drive water. All the seals between the cartridge sections, and between the cartridge and the outside environment, are hydraulically set through the remote running tool.

During the test period there were 20 start-ups and shutdowns, for reasons that were unrelated to the SMUBS booster station. This provided a good opportunity to study the start-up and shutdown transients and provided a great deal of data about performance under abnormal conditions. No operating problems were experienced and the pump showed stable operating performance over the 1,000-hour test run period.

Eastern Trough Area Project

Subsea booster pumps are also playing a significant role in the £1.6bn, BP-operated ETAP scheme which lies 240 km east of Aberdeen. The overall scheme involves the development of seven fields by means of a Central Processing Facility (CPF) connected to wellhead platforms and subsea satellites.

The Machar field, which will deliver 30% of ETAP's oil revenue, lies 35 km from the CPF. A tie-back of this distance would previously have required a separate wellhead platform. In the event, the use of subsea booster pumps was an important factor that enabled a subsea solution to be adopted for development of the field, resulting in a considerable cost saving.

Unprocessed well fluids are to be transported from the Machar subsea production systems to the CPF. The operator believes that during the early days of the field's life the reservoir will have sufficient pressure to convey the product through the pipeline. Water injection will be used to compensate for declining field pressure from 1999. The high pressure injection water will also be used to power two turbine driven multiphase pumps to maintain the plateau production level.

Framo Engineering is supplying two SMUBS units for this purpose and is working closely with the ETAP team to ensure that the design exactly matches the requirements of the reservoir. The multiphase booster pumps will be installed on an independent structure 30 metres downstream of the Machar production manifold in 84.5 metres of water. A common flow homogeniser will be installed immediately upstream of the two pumps in order to smooth out the effects of slugging.

Innovative technology boosts Lufeng

Lufeng 22/1 is a small, marginally economic field located 250 km southeast of Hong Kong which has been successfully exploited by the use of new technology and a fast-track development plan. The development, which makes extensive use of leased rather than purchased equipment, was approved by the Chinese Government in March 1996 and came onstream at the end of 1997.

The field was discovered by Occidental in 1986, but was considered sub-commercial at the time. The development work started at about the same time that Statoil acquired a 75% stake in the field through the purchase of Ampolex (Orient) Inc. The remaining 25% stake is held by the China National Offshore Oil Corporation (CNOOC).

The environmental conditions are extremely difficult with frequent monsoons and typhoons, and strong submarine currents known as 'Solitons'. The 333 metres water depth means that remotely operated vehicles (ROVs) must be used for all seabed operations it also makes this the deepest development so far undertaken in Chinese waters.

The field has complex geology and recoverable reserves of just 30mn barrels of 'waxy' crude oil (based on a 25% recovery rate). The high wax content means that the crude must be kept above 62°F so there are arrangements to pre-heat all process systems, steam heat cargo tanks and pig the flowlines to remove wax build-up.

The field is being developed by a subsea template with five production wells; the wells have horizontal sections ranging from 470 to 2,060 metres. The subsea template is connected by two flexible flowlines (to permit round-trip pigging) to a floating production, storage and offloading vessel (FPSO), the *Navion Munin*. Plateau production of 60,000 b/d is expected to last for three to four years after which a rapid decline will occur as water breakthrough takes place.

The *Navion Munin* is a multipurpose shuttle tanker (MST) with a deadweight of 103,000 tonnes and storage capacity for 640,000 barrels of oil. The vessel is owned by Statoil affiliate Navion, and is a sistership to the *Berge Hugin*. The tanker is of double hull design with steam heating for its cargo tanks. Extensive use of automation means that a crew of less than 40 workers will be needed. Norwegian expatriates will be employed in senior positions on the vessel during the start-up phase but will be gradually replaced by Chinese personnel.

The selection of a Kongsberg hinge over subsea template (HOST) leads to lower costs and shorter project time-scale. The HOST components are modularised and can be installed from a drilling rig, thus eliminating the need for a crane barge. The template is built up from standard building-blocks which can be combined in various scenarios. This reduces cost and manufacture time. The short manufacture time for this item was one of the main factors that made the fast-track development possible.

The field needs artificial lift to maintain economic production rates as reservoir pressure declines and water cut increases. The low gas/oil ratio meant that gas lift was not a practical option. This left downhole pumps or subsea booster pumps as possible options. The use of subsea booster pumps meant that the need for a mobile drilling rig (as used to support downhole pumps on the neighbouring Liuhua 11/1 field) could be eliminated. The Lufeng subsea booster pumps may be retrieved by workover equipment installed on the FPSO moored directly over the manifold.

The subsea booster pumps were supplied by Framo and are of similar conceptual design to those used in the Draugen field in the Norwegian sector of the North Sea, except that they are electrically driven. The five booster pumps have been integrated into the Kongsberg HOST subsea production manifold – one for each of the five wells. The pump cartridges are inserted into fixed receiver barrels by means of wireline running tools – the seals are also set during this operation.

The *Navion Munin* is the first vessel to have a compact process swivel and submerged turret production (STP) system integrated into a separate compartment within the vessel's hull. The STP system enables the vessel to disconnect from its STP submerged loading buoy when heavy weather is forecast. The vessel can remain connected in significant wave heights up to seven metres. The STP buoy floats 45 metres below sea level when disconnected.

The swivel system, which was also supplied by Framo, is mounted in a trolley system capable of moving it under extreme weather conditions. The overall system incorporates an electrical power swivel to provide 400 kW to each of the subsea booster pumps, a process swivel with two 7-inch flow paths, a hydraulic utility swivel and a control signal swivel.

Framo Engineering says that a full-scale verification test performed at Fusa, in Norway, contributed largely to the successful and swift offshore installation and successful field start-up during Christmas and New Year of 1997/98.

Under design conditions the 65,000 b/d high pressure injection water will be equally divided between the two turbine drive units. The injection water pressure will fall from 286 bar at the turbine inlet to 136 bar at the turbine outlet. This gives a 150 bar pressure drop across each turbine package.

Benefits and limitations

Subsea multiphase pumps provide oil companies with an economic alternative to downhole pumps for certain reservoirs. However, it must be recognised that there are fundamental reasons why downhole pumps will still be needed in many cases (such as the extent that a pump can raise fluids from beneath its inlet, and the evaporation of condensate on the suction side of a pump).

However, in the correct application, multiphase booster pumps located on the seabed can increase flow from the reservoir, and they can also increase the fluid export pressure to permit longer tie-back distances. In fact, it was the attraction of longer tie-back distances that provided the main impetus for multiphase pump R&D (there was a belief that 50 km tie-back distances would bring the majority of known deposits in the North Sea within reach of existing infrastructure).

From a practical point of view, subsea booster pumps are far more easily accessible than downhole pumps. A drilling rig is needed to retrieve a downhole pump from a subsea well, whereas subsea booster pumps can be retrieved by inexpensive wireline operations. A further practical advantage is that a subsea booster pump can handle the production of more than one well, and this flexibility opens the possibility of redundant systems with back-up pumps to cater for equipment failure.

Petrobras has appreciated the importance of subsea booster stations for its deepwater fields in the Campos Basin. It is currently developing its own SBMS500 subsea booster station for these deep-water applications.

South Korea reviews gas growth forecast

South Korea's Ministry of Trade, Industry and Electricity is finalising a review of the country's long-term LNG supply and demand programme which is due to be published this month. Originally due to be finished several months earlier, completing the review has been delayed by the recent presidential elections and the country's mounting economic difficulties, writes *David Hayes* who was recently in South Korea.

In recent years South Korea has experienced one of the highest gas consumption growth rates in Asia. LNG imports totalled 9.2mn tonnes in 1996 and were expected to reach 11.6mn tonnes in 1997. Half of the current gas demand is from power plants while one-third of LNG imports are used by household consumers. The remaining gas demand is from industrial and commercial users.

South Korea's financial crisis and the resulting downturn in industrial growth have raised questions about whether the country's ambitious LNG import programme will stay on track. Previously Korea Gas Corporation (Kogas) forecast that LNG imports would grow to 20.7mn t/y in 2001 before rising to 25mn t/y by 2006. By 2010 Kogas expected to import 29.3mn t/y.

However, South Korea's short-term LNG demand forecasts have been thrown into question by the recent slump in industrial output growth. In December 1997 industrial output growth fell to below 4% compared with 9.2% one year earlier. The Bank of Korea has attributed the drop in output growth to a slowdown in domestic consumption and reduced exports due to the current financial turmoil.

Although no official announcement has been made, Kogas is believed to be considering cancelling spot orders for LNG this year and possibly some short-term contract volumes after previously planning to import about 13.7mn tonnes in 1998. Already rumours are circulating that Kogas could reduce spot order and short-term contract purchases by over 2mn tonnes in 1998 pushing actual imports below 1997 figures, though not all observers believe the cuts will be so high.

LNG importer

Kogas is South Korea's sole importer of LNG, originally established by Korea Electric Power Corporation (Kepco) to import LNG for power generation. Kogas supplies Kepco's power stations direct from its transmission grid. All other gas is supplied through city gas companies which buy feedstock from Kogas for piped distribution to household, commercial and industrial consumers.

At the end of 1997 there were 32 city gas companies scattered throughout South Korea. Of these, 17 are located in areas were natural gas supplies are available for distribution to customers. The 15 other city gas companies are located in cities where natural gas is not yet available. These supply an LPG/air mix and will convert to supply natural gas by the year 2000 when Kogas is due to complete construction of its national gas transmission grid.

Cuts versus demand

Talk of LNG short-term import cuts comes at a time of annual peak gas demand in South Korea which is in midwinter, the coldest time of the year. Currently about 48% of the country's 10mn households are served by piped gas supplies. Following a massive housing construction programme over the past 20 years about half of all Korean families live in modern highrise apartment blocks served by piped gas.

'Gas demand is growing mainly because household consumption has increased in wintertime. Household demand has increased more than industrial and commercial demand,' commented a Kogas spokesperson. 'Individual households are using more gas. In 1994, for example, each household used 745 cm while in 1996 the figure was 957 cm. Many households use gas for cooking, but they use more gas for space heating and water heating. The government has set restrictions on using coal or oil in homes and commercial buildings in city areas so people are changing to gas.'

In 1996 South Korean households used 3.1mn tonnes of LNG accounting for 32% of the 9.2mn tonnes of LNG consumed in the country. Consumption is believed to have risen by one-third to about 4mn tonnes in 1997 and had been expected to reach 5.1mn tonnes in 1998. Kogas' currently under review long-term forecast suggests that household gas use will increase to 11.5mn tonnes in 2010 accounting for 40% of forecast gas consumption that year as more households are expected to convert their home heating systems to natural gas.

Industrial consumption of LNG is far smaller, standing at 660,000 tonnes in 1996 and accounting for just 7.2% of total LNG demand. Consumption was expected to reach 1.1mn tonnes in 1997 accounting for 10% of gas consumption. Forecasts of industrial gas use reaching 1.4mn tonnes in 1998 now seem unlikely to be achieved if industrial output growth rates continue to show a decline.

'Industrial gas consumption growth is not as high as household use as LNG costs more than other fuels and factories are not obliged to change to gas,' the Kogas spokesperson said. 'However, the government is increasing restrictions on fuel use for commercial buildings so more are converting to gas.'

Industrial consumption figures

Gas use by industry is smaller than Kogas' figures show as most gas consumed on industrial premises is actually used for space heating or cooling as well as cooking in factory staff canteens. Only a small volume of gas is used for industrial manufacturing processes. However, gas use for industrial processes is expected to grow in future as iron and steel mills and the ceramics industry are expected to install more gas burning process equipment as government control of industrial air pollution becomes more tightly regulated.

From today's modest industrial demand, Kogas expects industrial gas demand to begin growing more strongly after 2000 when Kogas' national gas transmission grid is due to be completed. With piped natural gas available in all major cities countrywide, industrial use of LNG is expected to increase to 3.4mn tonnes by 2010 accounting for 12% of South Korea's total gas demand.

Meanwhile, gas consumption by commercial customers is also expected to show a similar, though lower, growth trend to industrial gas use. In 1996 around 835,000 tonnes of gas were used for heating, cooling and cooking in hotels, restaurants and office buildings accounting for 7.6% of gas use. In 1997 commercial gas consumption was expected to reach 1mn tonnes accounting for 9% of gas demand.

Commercial use will increase in future although Kogas' forecast is that commercial gas consumption will remain unchanged as a proportion of total LNG use. By 2010 commercial gas consumption will reach 2.6mn t/y accounting for 9% of the 28.5mn tonnes of LNG South Korea is expected to import that year.

Supply and demand review

Meanwhile, the outcome of Kogas' ongoing review of long-term gas supply and demand is awaited with interest by local and foreign companies. Most industry observers expect Kogas to honour its long-term take-or-pay contracts though short-term contracts appear in jeopardy. The government remains committed to increasing the natural gas share of primary energy use which requires LNG imports to grow.

Kogas Head Office, South Korea

	Oil	Gas
1986	28.4	0.1
1987	29.8	2.1
1988	35.6	2.7
1989	41.0	2.6
1990	49.5	3.0
1991	59.9	3.5
1992	72.3	4.6
1993	79.3	5.7
1994	87.0	7.6
1995	94.8	9.2
1996	101.4	12.2

Source: BP Statistical Review 1997

S Korean energy consumption in mn toe

To comply with government requirements Kogas prepares a new long-term supply and demand plan every two years covering the next ten years. The last long-term review was completed in 1995. Kogas also carries out a medium-term review every year covering the next five-year period. The last plan was completed in 1996, which then showed increased demand being likely over the next few years.

To complete its long-term review Kogas needs to have long-term fuel purchase forecasts from its largest customer, electricity generator Kepco, which currently purchases almost half of all imported LNG. In fact, Kepco's own 10-year long-term review is underway concurrently with the Kogas review. Consequently Kogas is waiting for Kepco to finalise its fuel demand forecasts so that it can incorporate Kepco's LNG demand predictions into its own forecasts.

Although consultations and public hearings are continuing, Kepco's review is expected to result in a slight increase in long-term forecast generation requirements. While current economic difficulties are of serious concern the South Korean Government considers the nation's long-term economic prospects remain very bright with the result that slightly larger power plant facilities are expected to be needed in 2010 than were forecast in the government's previous long-term power development plan.

LNG versus nuclear

'Kepco is using more gas as there is no environmental problem with this fuel,' commented the Kogas spokesperson. 'Nuclear stations, however, require a long time to plan and construct. People are complaining and so Kepco cannot secure nuclear power plant sites. Coal-fired station projects face the same problem. Industries also are changing to natural gas as they have to obey environmental laws and regulations. Factories are not permitted to use polluting fuels.'

LNG advantages

Although LNG has to be imported and is more expensive per kWh of electricity generated than nuclear, coal-fired and oil-burning power stations, LNG offers a number of advantages to Kepco. As plants based on coal, oil or nuclear energy cannot be built close to urban areas, LNG is the obvious fuel for peak-load power sta-

	('000 b/d)
1990	755
1991	930
1992	1,300
1993	1,510
1994	1,530
1995	1,635
1996	1,815

Source: BP Statistical Review 1997

S Korean refining capacity 1990–96

tions that need to be sited in urban areas. Sited close to the load centre, gas-fired stations can supply growing peak-power demand that is rising each year due to the greater use of air conditioning in the summer and high demand for space heating during wintertime.

Combined-cycle stations offer a high thermal efficiency compared with other power stations and have the advantage that they also can be used to generate combined heat and power output to supply district heating. Another advantage is that many small and medium size gas turbine units are of a standard design and can be ordered off the shelf, which is a distinct attraction when a power plant needs to be installed in a hurry.

Gas-fired stations are likely to play an important role in future as delays in locating sites and obtaining planning permission for nuclear plants and coal-burning stations will mean that LNG-fired stations will continue to have the shortest lead time to construct. The Kogas spokesperson commented: 'Kepco plans to build more nuclear and coal fired stations, but their schedule faces delays so they do not have any choice but to increase the number of LNG-fired stations in future.'

By 2010 gas-fired power stations totalling 22,014 MW will represent 27.7% of Kepco's forecast total 79,551 MW installed capacity that year. By comparison nuclear stations totalling 26,329 MW will represent 33% of installed capacity, and coal-burning stations totalling 20,900 will represent 26.3% of installed capacity.

Site for new import terminal

Meanwhile, Kogas has recently selected a site for a third LNG import terminal as a key element in a huge US$7bn investment programme to be implemented from now until 2010 developing natural gas' share of prime energy use. Tong Young terminal will be located in the south of the Korean Peninsular where Kogas is currently building a transmission pipeline loop connecting Kwangju and Pusan. As both Pyongtaek and Inchon LNG terminals are located on the northwest coast near Seoul, the third LNG terminal is planned both to increase security of supply to the national gas transmission network and boost gas utilisation in the southern region.

The decision on the best site for the third terminal was made soon after Kogas commissioned its number two LNG receiving terminal at Inchon in October 1996. Previously Kogas imported all LNG supplies through its original receiving terminal at Pyongtaek. Work has been carried out to increase handling facilities at both terminals to cope with South Korea's rapidly rising LNG import needs.

Environmental study

Kogas is believed to have started an environmental study following the selection of the Tong Young site. If the results are favourable Kogas will begin construction this year to complete the new terminal in October 2002.

Gas use for power generation will create the initial baseload demand to ensure the economic viability of Kogas' third LNG terminal. Kepco plans to convert an existing coal-fired power station in Pusan to gas-burning as well as build a new combined cycle station to supply the industrial port city. Elsewhere in the southern region Kepco plans to build new gas-fired power stations in Taegu and Ulsan to use for peak load shaving.

Long term		1997	1998	1999	2000	2005	2010
Indonesia	Arun III (cif)	2,300	2,300	2,300	2,300	2,300	
Indonesia	Korea II (fob)	2,056	2,000	2,000	2,000	2,000	2,000
Indonesia	Badak V (fob)		970	970	970	970	970
Malaysia	MLNG II (fob)	1,850	2,000	2,000	2,000	2,200	2,000
Qatar				600	3,300	4,800	4,800
Oman	OLNG (fob)				2,000	4,060	4,060
Sub-total		**6,206**	**7,300**	**7,900**	**12,600**	**16,160**	**13,860**
Short term							
Indonesia	fob	1,288	1,344	2,362			
Indonesia	cif	1,232	952	168			
Malaysia	fob	1,288	672	672			
Malaysia	cif	1,026	627	114			
Sub-total		**4,834**	**3,595**	**3,316**			
Planned additional volumes*		**1,060**	**3,087**	**3,460**	**4,890**	**3,900**	**3,900**
Grand total		**12,100**	**13,982**	**14,676**	**17,490**	**20,060**	**17,760**

**Pre-crisis* *Source: KOGAS/Wood Mackenzie. Published in* FT International Gas Report 6.7.98

KOGAS Contracts 1997-2010 (million tonnes)

Have all the elephants been found? Part 2

In the second of our series on Dr Colin Campbell's book, *The Coming Oil Crisis*, *Petroleum Review* examines the impact that offshore drilling technology, seismic exploration, reservoir calculation and geopolitics have on yet-to-find and ultimate-recoverable estimates of conventional oil. We will also high-grade some of the last remaining exploration hot-spots in the world.

In his book Dr Colin Campbell notes that the world consumes about 24bn barrels of conventional oil annually, but now only finds approximately 6bn new barrels to replace it. Will advances in offshore drilling technology reverse that trend?

Industry observers can point to a previous period as proof that it can. During the late 1960s, as onshore discoveries began to decline, exploration companies turned to the continental shelf, the shallow offshore waters that ring the world's land masses.

Some onshore oil plays had long been assumed to extend on to the continental shelf, which varies from a few kilometres to more than 500 kilometres in width, and up to an average of 150 metres in water depth. Jack-up rigs (where drilling rigs stand on retractable legs resting on the sea floor), and semi-submersible rigs (where drilling rigs are mounted on pontoons), were developed to exploit the continental shelf.

Impressive new discoveries were made, including the North Sea and the Gulf of Mexico. By the late 1980s, 20% of conventional oil production was from offshore.

According to Colin Campbell, however, the continental shelf is now a mature play. 'Most of the oil remaining to be found will be discovered in ever smaller fields in existing basins.'

'The last 500mn barrel oil field found in the North Sea was in the 1980s,' says Richard Hardman, Exploration Director for Amerada Hess. 'Everyone is now looking for fields under 100mn. We recently found a field in the 25 to 50mn barrel range, and we were absolutely thrilled.'

As a result, exploration companies are currently pushing ever further into the oceans. The deeper continental shelf and 'continental slope' have become the new frontier regions.

The continental slope forms the seaward border of the continental shelf. It ranges in depth from 150 metres to approximately 3,000 metres. Recent advances in drilling technology have extended offshore drilling to over 1,700 metres water depth.

According to many explorers, the continental slope presents an attractive target. 'We only have a handle on less than 1% of the deep water,' says George Robinson, of Smith Rea Energy Consultants. 'There is good potential for finding very large amounts of oil.'

'We do understand deep-water geology fairly well, even if it hasn't all been drilled up,' counters Campbell. 'I think deepwater has a global potential of about 100bn barrels, and about 25bn barrels have been found.'

While the numbers look impressive, Campbell notes that the oil is often poor quality. 'Deep-water oil is nudging the non-conventional, and these discoveries won't realistically make any great difference to the global supply of conventional oil.'

Seismic

Advances in seismic technology have often been cited as a way of reversing the downward trend of new discoveries, and of adding to the 175bn barrels of conventional oil that Campbell predicts are yet-to-find.

'BP replaced 150% of what it produced last year,' says Keith Nunn, British Petroleum's Resource Team Leader for

Oil Reserves added bn b		Gas Reserves added tn cf		Reserves added mn boe	
1. Brazil	1,032	Egypt	9.27	Angola	64.1
2. Angola	0.802	Russia	8.22	Egypt	41.7
3. S Arabia	0.600	Argentina	2.56	Trinidad & Tob.	34.7
4. Nigeria	0.554	Indonesia	1.92	Brazil	20.9
5. UK	0.323	China	1.91	Papua N Guinea	20.0
World Total	**5.243**	**World Total**	**38.73**	**World Average:**	**10.5**

Comparable data unavailable for North America

** Only (48) countries with more than 5 nfws drilled in 1996 included. Other countries recorded higher ratios but drilled very few wells.*
Source: Petroconsultants SA

Table 1: Exploration performance 1996

Subsurface Imaging. 'You have better seismic data that is better imaged in three dimensions, and it allows for a whole magnitude of better interpretation. It's reduced our global average finding rate from one well in five to one in two.'

A seismic survey is a fast, cost-effective method of exploring the sub-surface for reservoir structures. It has long been used onshore and offshore, and can cover thousands of square kilometres.

A seismic survey involves transmitting energy, normally produced by an explosion or vibrating source. The energy travels down through the ground and is reflected and refracted back up to the surface, where its amplitude and time of arrival are recorded.

The data is then interpreted based on information regarding the density and composition of rock beneath the survey. The interpreted data is then typically displayed on a cross-section, or profile, with reflection/refraction surfaces corresponding to the boundaries between layers of rock. Seismic surveys can delineate faults, stratigraphic and structural traps, and even the presence of oil and gas in rock pores.

Three-dimensional seismic, or 3-D, is a higher-quality variation of traditional, 2-D seismic surveys. Advances in the cost and speed of computing permit data to be shot at a much denser spacing, allowing for the delineation of deeper, more subtle stratigraphic plays.

Recent advances in technology have made surveys much cheaper and more accurate. 'Before 1993, 3-D cost on average $15,000 per sq km, and took 15 months turnaround time,' says Nunn. 'Now, it costs less than $5,000 per sq km, and it takes three months to turnaround.'

Great strides have also been made in interpretation. Texaco recently opened a 3-D Visualization Center in Houston that uses a supercomputer to load up to 3,500 sq km of 3-D seismic data, and graphically display it on a concave screen 25 ft wide and 9 ft high. Geoscientists can virtually stand in the middle of the reservoir as they make decisions regarding drilling targets.

Nunn notes that 3-D is so effective at identifying a new play that few wildcat wells are drilled without it. 'The total amount of 3-D seismic has shot up tremendously, to around 5mn km (based upon a common-mid-point conversion) per year.'

In addition, 3-D will identify significant traps that 2-D cannot. 'Offshore West Africa has many channelised reservoirs that simply do not show up on 2-D grid spreads of 1 to 2 km,' says Nunn. 'In one block alone off Angola, there were two major discoveries in excess of one-half billion barrels each.'

'There are certain areas like the deep-sea offshore West Africa where 3-D is indispensable, but much of the world's oil was found without it,' notes Campbell. 'It is not a panacea that opens up huge new possibilities. Most of the traps that depend on 3-D are relatively small.'

Campbell does not wish to downplay 3-D as an effective exploration tool, however. 'We've got 175bn barrels yet-to-find, and unless they do use technological advances like 3-D, they won't even make that.'

Reservoir estimation

There is a great deal of variation over estimates of how much oil can be ultimately produced around the world. Campbell quotes an ultimate recoverable figure of 1.8tn barrels of oil, compared to the United States Geological Survey's latest figure of 2.3tn barrels. Who is correct?

Much of the variation arises from the lack of a standard definition for 'reserves'. Geological science is not precise enough to establish exactly how large the amount of oil that is ultimately producible in a reservoir will be until the last barrel is pumped. Until then, the number is no more than an estimate having a probability ranking: it is possible to make both optimistic or conservative estimates as desired.

A median case reserve (P50), means that the risks of the actual recovery proving higher or lower than the estimate are equally matched. A high case (P5/10), means that there is a very low probability that the optimistic reserve estimate will actually be confirmed. A low case (P90/95), means that there is a very high probability that the conservative reserve estimate will actually be confirmed.

Ideally, the median case reserve should be used, but because there is no universal rule regarding which number to use, probabilities can be chosen to suit particular needs.

When an undrilled prospect is first delineated, geologists are often under pressure to overstate potential reserves by using a high case probability.

Once a new field wildcat well is drilled and oil discovered, however, the company responsible for exploiting the field doesn't want to overspend on production facilities, and tends to choose a conservative, low case estimate, which understates the actual amount. As more wells are drilled and production figures accumulate, the estimate of reserves generally rises along with the confidence level regarding the accuracy of the figures.

This growth in reserves over time due to probability estimate adjustment can cause confusion. 'Economist and others not only claim that the apparent improved recovery is due to technological advances, but further impute future increases from the ever onward march of technology,' says Campbell. 'In reality, it is simply a result of moving from a low initial development estimate to what the field actually delivers.'

Because there is no universal standard, adds Campbell, it is possible to report whatever reserves suit the corporate need without specifying the probability ranking applying to them. 'Companies can under-report to spread out their assets and maintain the illusion of replacing reserves.'

'The Securities Exchange Commission has strong powers to monitor and control the volumes reported by companies, and auditors act as an important additional check,' counters Francis Harper, a geological consultant with British Petroleum. 'Most of this control is to prevent companies overstating reserves, and hence misleading shareholders, but companies rarely have the luxury of being able to deliberately understate reserves.'

Reserve estimates are also manipulated for political purposes. Campbell notes that Mexico inflated its reserves for the purposes of collateral, and several OPEC countries exaggerated their reserves in the late 1980s in order to secure higher production quotas.

'It is true about Mexico,' agrees Dr Manouchehr Takin, Senior Petroleum Upstream Analyst for the Centre for Global Energy Studies. 'They publicly acknowledge the reserves have been exaggerated.'

Dr Takin is more cautious about Opec, however. He notes that after nationalisation in the 1970s, many Opec countries continued to explore aggressively for oil, but, until recently, treated the information as a state secret. 'As a result, they were quoting reserves from 20 years in the past.'

Even though much secrecy still surrounds reserve figures in the Middle East, for the most part, Dr Takin thinks that the official numbers are relatively accurate. While Iraq's official reserves suddenly doubled from around 50bn barrels to 100bn barrels in 1988, for instance, Dr Takin believes the higher number is well-grounded within professional estimates. 'When you talk to people in the fields, and you talk to the experts who have experience in that country, 100 to 110bn barrels of reserves is a reasonable figure.'

'It's important to note that the

	2-D Seismic* ('000 line km)		3-D Seismic* ('000 km²)		New Field Wildcat Wells	
1	Mexico	76.5	UK	22.1	USA	1,572
2	Australia	57.0	Norway	21.9	Canada	198
3	India	36.1	Egypt	7.2	Australia	116
4	Norway	32.6	Nigeria	6.9	Argentina	87
5	Brazil	25.7	Angola	6.7	Russia	86
World Total:		**553.0**	**World Total:**	**118.4**	**World Total:**	**2,889**

* Comparable seismic data unavailable for North America and CIS
Source: Petroconsultants SA

Table 2: Exploration activity 1996

Middle East reserves added in the late 1980s were not due to technological reasons,' says Campbell. 'They should have been backdated 50 years to the date of discovery, which is not the case. It gives the impression of a whole lot of new discoveries, which is not true.'

Politics

In the last decade, many countries around the world have reopened their borders to international exploration. The Former Soviet Union, China, Venezuela, Brazil and many other countries with prolific oil zones have liberalised their regulations and abolished state monopolies. But will the influx of international exploration money result in huge new discoveries?

'The prospects in the Former Soviet Union and China are not well known in the West,' says Campbell. 'This ignorance has tempted some to attribute a large undiscovered potential to these areas.'

Campbell thinks that their optimism is premature. 'There is certainly scope to extend known trends offshore into the Caspian, which was not investigated by the Soviets, but I think that the Soviet explorers were certainly as intelligent as their western counterparts, and the systematic exploration of the Soviet system was probably efficient. I therefore think that all the large productive basins have been found as well as most of the giant fields.'

Campbell accepts that there may be some scope for exploration in remote areas in China, but others are sceptical. 'BP spent a lot of time looking at offshore China, without success,' says the company's Francis Harper. 'We also pulled out of the Tarim Basin because it was disappointing. We've learned to be very cautious about China.'

Dr Takin points out that most of the international areas that are now being licensed to foreign companies are merely being reopened after several decades of exclusion, and that international oil companies already had a good idea what the resources were before the wave of nationalisation took place. 'There will be many new finds due to advanced technology, but we're not going to see a doubling of Iranian reserves due to new exploration, for instance,' he notes. 'There are no prolific basins that have been kept virgin for political reasons.'

Conclusions

Improvements in drilling will open up new large fields in deep water, but the trend will have much less impact on global production than continental shelf discoveries had during the 1970s and 1980s.

The growth in worldwide reserves in the last decade is due primarily to a lack of universal reserve definitions, rather than an increase in the discovery rate. Recent additions to Middle East reserves were late reporting, for instance, and not new discoveries or revisions due to advanced technology.

The worldwide liberalisation of government policy will not open up previously unexplored prolific basins.

Advances in seismic technology will be critically important in finding the remaining yet-to-find, primarily by helping to delineate smaller and smaller targets.

But, in the end, will technology add to Campbell's estimate of 175bn barrels of yet-to-find? 'His estimate is at the low end of industry consensus,' says BP's Francis Harper. 'Advances in technology will not only help us visualise what's down there, but it will also help us target it and get the oil out. I prefer an estimate of about 300bn barrels of yet-to-find.'

In our concluding article of the series, *Petroleum Review* will examine the impact that increased productivity will have upon ultimate reserves.

Current exploration hotspots

Gulf of Mexico

Exploration in the US deep-water portion indicates ultimate resources up to 20bn barrels, and the Mexican portion may double that number.

FSU

The Caspian has the greatest potential for new discoveries in the Former Soviet Union. Some experts think prospects beneath the Caspian Sea may have ultimate resources of several billion barrels, but at this point it is merely a prospect, and needs to be tested.

Sakhalin Island

Paleodeltas related to ancient river systems have created several shallow water fields in excess of 1bn barrels and 1tn cf of natural gas. Conservative estimates place ultimate resources for the region at 20bn barrels.

West Africa

Several giant fields, including Dalia and Girassol, at one-half billion barrels each, have recently been discovered in deep-water turbidite reservoirs. Insufficient published data also makes an ultimate resource estimation for the region difficult, but may run as high as 30 to 40bn barrels.

Offshore Brazil

A mirror image of West Africa, geologically. The Marlim and Albacora fields, in reservoirs created by turbidites, are well over 1bn barrels each. Reserves for the region are estimated at 20 to 25bn barrels.

Refining margins – the benchmark paradox

As *Petroleum Review* readers will have noted from our news pages and our News in Brief Service on the IP website, the major oil and gas companies have been announcing their 1997 fiscal results over the past few months. However, is it possible to directly contrast and compare figures between companies? Paris-based analyst Enerfinance's European Downstream Monitoring Service addresses this question in relation to the refining sector of the industry.

Analysis of the global competitive environment for the European refining industry varies according to the refining benchmark used, says Enerfinance in a recent analysis of refinery margins. The typical European refinery is usually assumed to be in Rotterdam.

From this base case, margins improve by about 10 cents if a FOB* barge quotation is used whereas margins decline if a NWE FOB* cargo base or a combination of CIF/FOB NWE* basis is used.

The situation is further complicated if a monthly margin weighted by processing volumes is used instead of a simple average. In this case margins can differ by between zero and three cents. On the other hand, one trend which most benchmarks seem to have registered is the slight improvement in cracking margins – measured as a differential between the margin for a fluid catalytic cracking/visbreaker (FCC/VB) refinery and that for a topping/reforming refinery – which rose from $2.03 in 1996 to $2.13 in 1997.

Based on a Brent supply, these differences in margin valuation are summarised in **Table 1**. On average, these traditional benchmarks (using unchanged yields over the years and fixed valuation rules) show a stabilisation of refining margins during 1997. However, is it correct to say that the wider business environment remained unchanged between 1996 and 1997?

Corporate performances appear to indicate otherwise. TOTAL, for example, recently stated that its refinery benchmark gained 20 cents per barrel, from $1.93/b to $2.13/b. Shell reports a rise of around 10 cents, in line with Fina's own year-end conclusions, while on the other hand, BP declared that refining margins had weakened. (Note that these companies speak of gross refining margins, ie before currency and cost reduction efforts.) How are these differences explained?

In some cases it is only a matter of different price quotations, as shown in **Table 1**. In others, differing margins can be explained by more subtle methodological differences:

- Some companies calculate their benchmark by using a basket of crude rather than a single crude, supposedly in order to better reflect the average crude slate of a typical refinery.
- Others take into account the minor changes in refinery yields which result from a change in the product mix or from making better use of some units – a trend they believe is affecting a typical European refinery.
- Some companies will modify slightly the relative weight given to FOB and CIF quotations in order to account for the change in supply/demand that may affect the European market year to year.
- Finally, analysts sometimes argue that because a benchmark is designed to indicate an industry trend rather than an absolute value, changes in the parameters make no sense.

Until recently the fact that different benchmarks were used across the industry did not matter since trends were generally correlated. However, in 1997, trends themselves differed widely one from the other: BP's benchmark showed a negative trend while Shell and TOTAL showed positive trends.

With the loss in correlation, the very concept of a simple benchmarking indicator is losing relevance in explaining oil company performances.

Moving from margins analysis to oil company refining and marketing profits, a further 20 to 30 cents should be added to the 10-cent increase in gross margins (at constant currency and cost conditions) due to the rising dollar currency. This is because a majority of European oil companies express operating costs in local currency not dollars. This effect was limited for the UK, since the dollar value of the sterling remained basically unchanged.

Finally, three to four cents should be added due to the rise in the average utilisation of existing units, lowering operating costs per barrel produced.

In all, a typical European oil company having no more than 15% to 20% of its refining assets in the UK should have experienced a rise in refining margins of between 30 to 33 cents, or nearly 15% of the base case in 1996. Taking into account the ongoing cost reduction programmes at many refineries, the potential improvement in operating profit should be close to 40 cents per barrel.

Not only does Enerfinance believe this to be the relevant benchmark

cont'd on p37

	FOB basis				CIF basis	
	NWE	Barge	Med	Weighted*	NWE	Med
1985	1.51	2.06	1.41	1.69	2.23	2.37
1996	2.00	2.56	1.83	2.19	2.74	2.83
1997	1.96	2.68	1.76	2.18	2.72	2.74
Change						
96/97	0.49	0.50	0.41	0.50	0.51	0.46
97/96	(0.05)	0.12	(0.07)	(0.01)	(0.02)	(0.09)

**50% NWE, 20% barge and 30% Med; 100% Brent supply, fluid catalytic cracking/visbreaker refinery (FCC/VB)*

Table 1: Refinery benchmark ($/barrel)

Insuring risk in new frontiers

A few years ago, many countries outside the OECD opted to reserve their exploration acreage for state oil companies. However, recent changes in the economic and political climates of these countries have encouraged many governments to offer upstream opportunities to multinational oil companies who, with their advanced technology – much of which is especially geared to reducing costs – are showing substantial interest in the 'new' areas of rich potential in Latin America and elsewhere. Deregulation in the downstream sector is also encouraging overseas participation. The advent of this new interest has brought with it the need for tailored insurance solutions. David Whiting, Chief Underwriting Officer, Onshore Property, and Luis Prato, Regional Representative, Latin America, both of Zurich Global Energy, outline some of the challenges insurance providers face.

In areas where regulation of the oil industry is variable and existing equipment often outdated, insurance providers are being faced with a number of political, social and financial challenges which they must confront in order to support the energy companies as they pursue exploration in these new areas.

Latin America is particularly attractive for investment because of the region's heterogeneous nature. Unlike the Asia-Pacific, the economies of the Latin American countries are each in themselves fairly self sufficient and, therefore, an economic crash in one country would not present the same type of catastrophe as it would – and has – in Asia. While the potential for greater economic stability does exist, the region also presents a number of challenges – particularly for insurance providers.

Latin American challenges

The historic ownership of energy infrastructures in Latin America by the federal governments has resulted in a relative lack of investment in the maintenance of refineries, pipelines and terminals. Many of the facilities are not new and, as a result, insurance providers have been hesitant to insure these risks.

A further challenge resulting from government ownership of energy infrastructures is that companies are bound by law to tender their insurance programme (put out to bid) on a regular basis. This hinders oil companies from developing long-term relationships with the international insurance market.

There are also unique legal requirements in Latin America that impact insurance related activities. For example in Brazil, the constitution (which dictates all insurance purchasing) insists that all reinsurance has to be funnelled through the IRB (Instituto de Resseguros do Brasil) which determines how the exposure will be ceded out. This can severely limit the options and creativity for risk managers as well as impact the relationship building between the insurance provider and the risk manager.

With a trend toward privatisation there will be an influx of energy infrastructure investment. While this certainly presents insurers with an enormous opportunity there will also be a need for insurers to act as advisers to the local industry on a spectrum of risk management and risk engineering expertise. Traditionally, the Latin American energy industry has purchased insurance as if it were a commodity, a low-deductible maintenance policy. The risk managers of many of the organisations focusing on this area are now looking for guidance from the risk solutions provider on how to purchase insurance more effectively as well as how to maintain the facilities better to ensure coverage and minimise losses.

Depending on their business development focus, the risk management needs of each Latin American energy company could differ. For example some organisations are interested in further developing their operations internationally and as a result require an insurer with global capacity and the expertise and resources to help them manage risks worldwide. Others are more interested in expanding their operations within the region and therefore require a risk provider who can operate locally and understands the local issues. One challenge the latter scenario can present is that many of the local insurance companies are not structured to afford the capacities which the largest companies (which are often involved in the energy industry) require. As a result a local company providing the direct insurance, would need to work with an international insurer who would supply capacity by reinsuring the local company.

Risk managers need the support of an organisation with a local presence that can respond as rapidly as the market is changing. This is a dynamic region in terms of technology, politics, and economics. Insurers require the local presence, capabilities and networks to adapt and respond quickly and effectively to these market changes.

In summary, key challenges for the energy industry in Latin America are understanding the legal, cultural and political environments of the region as well as having the capability and local resources to respond quickly to these rapidly changing markets. Local presence is particularly important in this new frontier because of the value Latin Americans place on building personal relationships with business associates.

Developments within the oil sector are commanding change in the way insurance providers operate. As a risk solutions provider one must respond to the need for a local 'hands-on' approach. In an age where face-to-face contact seems to be fast disappearing, insurance providers for the Latin American energy sector need to stay in tune with this rapidly changing region.

Zurich Global Energy provides large-limit, multi-year risk solutions for multinationals involved in the exploration, development, production, processing, servicing, transportation and distribution of energy resources. With underwriting offices in Bermuda, Chicago, Houston, London, New York, Oslo and Zurich and regional representatives covering eastern Europe and CIS, Latin America and the Far and Middle East, it seeks to offer energy enterprises a full range of traditional and tailor-made risk solutions, supported by a risk engineering and claims handling service.

Zurich Global Energy is a business unit of Zurich Group.

Refining margins cont'd from p36

against which to measure 1997 results, its research also suggests that benchmarks are useful only if they integrate those changes in the competitive environment which any typical refinery should have been able to benefit from. In this view, a large currency movement should be integrated, even if the ability to compare margins from one year to the next declines with time.

A global refinery benchmark integrating all relevant factors bearing on a typical European refinery will soon be available from Enerfinance's European Downstream Monitoring Service.

** FOB – free on board, NWE – north west Europe, CIF – carriage insurance freight, Med – Mediterranean.*

The route to gas emissions trading

The year 2000 is seen as a milestone on the road to the future. However, many businesses obsessed with the threat of computer meltdown are missing other threats and opportunities for their businesses. The UN has recently announced that it aims to launch a market for trading in greenhouse gas emission allowances and relocation credits by the year 2000. Few businesses understand the impact of this on their operations. *Geoff Haley*, Partner, S J Berwin & Co, London, and *Frank Joshua*, Head, Greenhouse Gas Emissions Trading, UNCTAD Secretariat, Geneva, explain the next steps being taken to raise awareness throughout the world.

In preparation for the Kyoto meetings, in November 1997 UNCTAD (UN Commission on Trade, Aid and Development) and the Earth Council established the Greenhouse Gas Emissions Trading Policy Forum. The aim of the Policy Forum is to provide support to governments, corporations and other bodies in their efforts to design and implement an international greenhouse gas emissions trading system in accordance with the terms of the Kyoto Protocol to the UN Convention on Climate Change.

The aim of the Forum is to launch a market for trading in greenhouse gas emission allowances and reduction credits by the year 2000, thus contributing to the early and effective implementation of the Kyoto Protocol.

The Policy Forum is dedicated to facilitating constructive discussion among a core group of government policy makers, corporate executives and leaders of non-governmental organisations for the purpose of identifying feasible steps to implement the trading market. This includes assisting the parties to the Kyoto Protocol in their efforts to establish a comprehensive regulatory framework for emissions trading and assisting national authorities and market makers in their efforts to develop efficient trading rules, trading instruments and supporting institutions. This work will include defining the tradable commodity, accounting, monitoring, certification, reporting structures, results of non-compliance, and enforcement.

The success of the US sulfur dioxide allowance trading programme in dramatically reducing SO_2 emissions well ahead of schedule, and at significantly lower cost than had been predicted, provides a proven model that emissions trading can bring early and quantifiable environmental, economic and social benefits.

Collaboration

The issues arising from the proposed trading require close consultation and coordination among the large number of participating countries, corporations and other institutions. UNCTAD and the Earth Council, as co-sponsors of the Policy Forum, will ensure regular coordination with the Climate Change Secretariat and other international and corporate trading initiatives such as OECD and IEA, the World Bank, the International Panel on Climate Change, Global Environmental Facility and the Centre for Clean Air Policy.

The Policy Forum has established two working groups:

- *The Policy Framework Working Group* will assist the parties to the Kyoto Protocol in their effort to establish a comprehensive regulatory framework for emissions trading, including defining the tradable commodity, accounting, monitoring, certification, reporting, non-compliance and enforcement. The Group is chaired by Maurice Strong, Chairman of the Earth Council, Executive Coordinator for UN Reform and Senior Adviser to the President of the World Bank.
- *The Market Design and Operators Working Group* will assist national authorities and market makers to develop efficient trading rules, trading investments and supporting institutions. It is chaired by Richard Sander, Chairman of CEO, Centre Financial Products Limited, Chicago.

The activities of the Forum are overseen by a steering committee, co-chaired by Maurice Strong and the Secretary General of UNCTAD, Rubens Ricupero.

Plan of action

The Policy Forum has prepared a work plan in order to achieve the aim of launching a market for trading in greenhouse gas emission allowances and reduction credits by the year 2000. Initial immediate priorities are:

- SO_2 allowance trading (US)
- Gasoline lead reduction trading (US)
- Fisheries licence trading (New Zealand)
- RECLAIM (Regional Clean Air Incentive Market) programme (US).

A number of technical issues will also be considered:

- Measuring, monitoring and verification of emissions
- Certification of emissions performance, emissions reductions and allowance transfers or acquisitions
- Accountability and risks in international emissions trading
- Reporting requirements pursuant to the Kyoto Protocol.

An additional priority for the Policy Forum is the drafting of an international agreement that outlines the rules to govern the trading programme. This agreement would be an instrument of international law established in accordance with the UN Framework Convention on Climate Change.

UNCTAD is also actively promoting education and training throughout the world to achieve a better understanding of the emissions trading proposals. Conferences are planned for major centres in the world – the first conference being held in London on 11 and 12 May 1998 (refer to p45 for further details).

Cenelec certified gas detection

Zellweger Analytics has introduced a new Digi Cenelec certified range of specialist transmitters for gas detection applications. The range includes two transmitters – Digi-Cat and Digi-Ana – featuring 4-20mA output signal, local LED display of gas concentration, explosion-proof housing and a choice of either local or remote sensor mounting.

Individual transmitters are designed for use with specific gases. The Digi-Cat, which interfaces with a catalytic sensor, detects combustible gases (0–100% LEL (lower explosive limit)) while Digi-Ana, which interfaces with an uncalibrated current output sensor, covers combustible gases (0–100% LEL), toxic hydrogen sulfide (0–50 ppm), carbon monoxide (0, 100, 200, 500 ppm) and oxygen (0–25% v/v).

Both transmitters have aluminium housings and can be simply calibrated by one person. Each operates within a -20°C to +40° C range. High temperature versions, capable of handling up to +55°C, are available subject to certification.

Tel: +44 (0)1202 676161
Fax: +44 (0)1202 678011

Disposable gas and vapour respirator

The new Moldex 5000 Series disposal, half-mask gas and vapour respirator is supplied pre-assembled and ready for use. Lightweight and completely maintenance free, the respirator has been designed for use in any application where combinations of gases, vapour and fine particulates may be found.

The unit comprises a single facepiece and twin, integral, activated charcoal cartridges. Available in A1, A2 and ABEK configurations, the cartridges are designed for use until breakthrough occurs, ie when the contaminant can be detected by either taste or smell.

The respirator conforms to EN405 and features a strategically placed exhalation valve with protective grille to ensure low breathing resistance while providing optimum protection.

The unit also features the Moldex patented particle filter disc system which utilises a simple push-fit design to enable P1, P2SL or P3S/SL filters to be fitted over the gas filters.

Unlike other disposable gas and vapour cartridge respirators where the particulate filter system is integral to the facepiece, this new design is said to enable clogged dust filters to be replaced quickly and easily, states the manufacturer. As a result, the life of the gas and vapour cartridge is prolonged and end-user costs reduced.

The unit's dual material, injection moulded design is said to reduce overall weight while improving user comfort. It combines a polypropylene outer facepiece with a Kraton* cushion-fit inner face seal.

The company has also recently published a 40-page *Moldex Respiratory Contaminant Guide* to airborne contaminants commonly found in the workplace. Providing data on over 1,000 potentially harmful respiratory hazards listed in alphabetical order the guide also suggests the most appropriate form of respiratory protection equipment.

**Kraton is a thermoplastic material which is odourless and, unlike silicone, can be used in paint spraying applications.*

Tel: +44 (0)115 985 4288
Fax: +44 (0)115 985 4211

Portable oil skimmer

The Abanaki Tote-It® Portable Oil Skimmer is now available with steeper troughs, a larger discharge outlet and a redesigned tail pulley to meet a wider range of oil removal needs.

The new 1-inch to $1^1/_2$-inch outlet port and steeper troughs allow the skimmer to discharge more viscous oil at higher flow rates while the redesigned tail pulley is said to reduce wear and tear on the unit's belt, thereby increasing service life. Flanges on the pulley allow it to roll freely on the inside of the belt without becoming dislodged.

The lightweight unit requires a small operating area and can be easily mounted almost anywhere, states the manufacturer. Belts are made of corrosion-resistant steel or a specially engineered 'polybelt' material available in 1-inch, 2-inch or 4-inch widths. Standard belt lengths range from 18-inches to 60-inches in 6-inch increments. The device is suitable for a wide range of applications; including wastewater sumps; parts washers; coolant systems; and parking lots, garages and service facilities.

An optional oil concentrator is available to further separate oil from water or coolant after initial discharge.

Tel: +1 440 543 7400
Fax: +1 440 543 7404

Gas monitoring system range for the new millennium

A new range of gas detectors, controllers and emission monitors has been unveiled by TQ Environmental. The systems have full Cenelec certification and are manufactured in accordance with ISO 9001 quality standards. Many of the detectors and controllers also have type approval from ABS, Lloyds and DNV.

The TQ Millennium range includes highly accurate, electrochemical ozone detectors for both low ppb levels and high ppm detection, refrigerants and volatile organic compounds. The sensors can be utilised as ambient air leak detectors or within extractive continuous emissions monitors and are available in safe or hazardous area formats.

The GB100 infra-red sensor can be used as a point detector for the detection of flammable gas/vapour or carbon dioxide. The unit can also be used as an in-situ process analyser mounted directly in the gas flow. Such an arrangement is said to be ideal for the direct monitoring of digestor or landfill gas. The detector is also claimed to provide instant response to a change in gas concentration, suffer no poisoning effects and can operate in an inert atmosphere.

Other gases monitored within the range include: hydrogen sulfide (H_2S), carbon monoxide (CO), hydrogen cyanide (HCN), phosgene ($COCl_2$), phosphene (PH_3), arsine (A_5H_3), nitrous oxides (NO_x), sulfur oxides (SO_x), ammonia (NH_3) and solvents.

Tel: +44 (0)1924 380700
Fax: +44 (0)1924 361700

Tailor-made autocontrol sampling system

Jiskoot has developed a tailor-made autocontrol sampling system for the Tunisian Ghadames Oil Pipeline project that is reported to provide accurate sampling of crude oil while reducing operating costs.

Crude oil quality and quantity needs to be determined to ensure accurate valuation. Although water content in oil cannot be avoided, the financial losses resulting from this can be, states the company. The sampling system determines water content and the barrel price is adjusted accordingly.

The tailor-made system provides flow-proportional or time-proportional readings at import and export points. Each system includes an external sampler probe adjacent to the pipeline that collects the sample which is then stored in one of the two sample receivers connected to a mechanical scale. As one receiver is filled, the sensor within the scale signals and the second receiver takes over. The full receiver is then ready for removal and analysis.

In-line sampling system

Tel: +44 (0)1892 518000
Fax: +44 (0)1892 518100

Patented groundwater cleansing system

A new pumping system for groundwater cleansing and the recovery of floating layers of product was recently successfully deployed by Belgian land remediation company Soils NV in two pilot projects in Antwerp.

Unlike traditional approaches which usually involve the use of two pumps (one for water, the other for product) in each extraction well, the patented 'Extravac' system permits fully independent extraction from a large group of wells, linked via a collector to a single surface pump. The system is capable of handling 30 or more extraction wells, with the well unit's intake opening installed at the required depth in each well. Each well unit is capable of independent operation, with a dynamic, self-regulating block avoiding the vacuum drop problems associated with traditional methods.

The system offers the option to concentrate on the removal of floating product layers or, if required, the simultaneous lowering of the water level and the pumping of product. It is said to be virtually unaffected by soil particles, viscous/sticky liquids and sand.

Tel: +32 3 250 5211
Fax: +32 3 250 56 50

Focus on forecourt marketing

UK fuel control and forecourt automation company Meggitt Petroleum Systems is to launch a new customer operated point of sale system (COPOS).

Combining the customer display from the pump together with the company's established outdoor payment system into one single touch screen unit, the COPOS system will allow the forecourt to become a marketing platform for the host of products and services currently offered at the service station and for those which will develop as the demand for convenience style retailing increases, states the company. The system will enable the customer to view special offers, check loyalty point status and purchase fast food or a car wash without the need to visit the forecourt shop.

Meggitt also offers a fully integrated POS and pump control system – the 9500 – which is said to operate with a minimum of key depressions. Based on an 'if it flashes press it' philosophy, the system also gives selectable prompts to ensure that the site management's instructions are carried out. The 9500 system can network up to five pay positions, each tailored to site-specific requirements, including convenience store and quick service restaurant operations. The POS system also offers service station specific facilities such as combining two fuels sales per transaction; multi currency; attendant tagging; and cheque printing and validation.

Tel: +44 (0)1254 682111
Fax: +44 (0)1254 697567

NEWS Technology

Multi-gas monitoring in confined spaces

The new ISC Model ATX612 Aspirated Multi-Gas Monitor is designed to meet the requirements of confined space regulations. The unit simultaneously monitors the atmosphere for oxygen content, combustible gases and – by using interchangeable, field replacable sensors – up to two toxic gases, including carbon monoxide, hydrogen sulfide, sulfur dioxide, nitrogen dioxide or chlorine.

A liquid crystal display provides a continuous direct readout of all monitored gas concentrations at a single glance. One-button operation and calibration reduce the time and cost associated with training confined space entry personnel to operate and calibrate the instrument, states the manufacturer. Optional data logging can provide record and analysis of the entrant's gas exposure.

For pre-entry testing, the device is equipped with an internal constant flow pump that will draw remote gas samples from up to 100 ft away. Automatic compensation ensures that a continuous steady flow rate is maintained as sampling distances increase and as sample

lines and filters become dirty. A built-in dust/filter water stop protects the pump and sensors from damage caused by drawing liquids into the instrument. A low flow alarm is activated when the air sample to the sensors is inadequate or the pump malfunctions.

The ATX612 is powered by either nicad or alkaline battery packs, providing up to 24 hours of continuous use. A 90 dB audible and ultrabright visual alarm give immediate warning should the atmosphere become hazardous.

Tel: +44 (0)1902 227722
Fax: +44 (0)1902 227733

Detecting flammable gas hazards

The Draeger Pac Ex Personal Flammable Gas Detector is specifically designed to immediately indicate the presence of flammable gas hazards. Weighing just 370 grammes and claimed to be one of the smallest instruments of its kind, the handheld unit is particularly suited for use by petroleum officers as well as fire investigation and incident teams.

The detector can be calibrated for petrol, diesel and other flammable gases and features both audible and visual alarms. It can be configured for operation as a direct reading instrument at 0–5% v/v, 0–100% v/v or 1–100% LEL, or as a simple Go/No Go warning device. Providing up to 10 hours of operation, the unit can also be set to autorange between 0–110% v/v.

The gas detector features ingress protection to IP65 and Ex s IIC T4 hazardous area approval. Gas concentration and remaining battery life are clearly indicated via an integral, illuminated liquid crystal display. Protected from overload and deep discharge, the remaining battery capacity is shown in increments of 10%.

In addition to two low battery alarms, the unit is supplied with four user adjustable alarm levels which are factory set to 10% or 20% LEL, or 1% or 2% v/v methane.

The Pac Ex is password protected and allows a number of user adjustments to be selected. These include the selection of % LEL or % v/v measurement ranges, alarm settings and zero or span calibration.

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

Measuring nitrogen oxides in flue gases

The new Servomex 4992 NO_x Converter recently launched by Servomex International is designed to measure total oxides of nitrogen (NO and NO_2) in flue gases.

According to the manufacturer, until now, determination of NO_x has utilised a standard feature of the NO measurement module of the company's standard Xentra 4900 continuous emissions analyser which makes it possible for the NO_x level in the flue gas to be calculated from the measured NO level by applying a known relationship between levels of NO and NO_2. The new 19-inch rack-mounting 4992 NOx Converter, however, has been developed to provide a precise actual measurement for those applications where a calculation is not acceptable.

The unit converts NO_2 to NO in a quick-chilled extracted gas sample. The dry, conditioned and filtered sample of flue gas must have a dew point of less than 6°C, be filtered to better than 1 μm and contain at least 0.5% oxygen. The stainless steel converter typically operates at 650°C and features a high efficiency, high flow design suitable for use with infra-red NO analysers. A user-selectable bypass solenoid valve makes it possible for the user to switch between NO and NO_x measurement.

The manufacturer states that the new converter unit can be retrofitted to existing continuous emissions monitoring installations where precise measurement of NO_x levels would be beneficial.

Tel: +44 (0)1892 652181
Fax: +44 (0)1892 662253
e-mail: info@servomex.com

If you would like your new product releases to be considered for our Technology News pages, please send the relevant information and pictures to:

Kim Jackson

Deputy Editor, *Petroleum Review*

61 New Cavendish Street, London W1M 8AR, UK

NEW Publications

Nigerian Petroleum Business: A Handbook

Editor: Victor E Eromosele (Available via the commercial attaché at your nearest Nigerian Embassy or direct on Tel: +234 9 523 9149 or +234 1 837870; Fax: +234 4 523 2971 or +234 1 585 0053). ISBN 978 33459 3 1. 560 pages. Price: (hardback): UK – £84 (incl p&p); US and elsewhere – $130 (incl p&p).

In 40 selected readings written by 30 authors within and outside of the oil and gas industry, this publication documents the unique Nigerian business environment and the salient aspects of the maturing petroleum industry of what is Africa's largest oil producing country. The text is supported by a glossary of petroleum terms commonly used in Nigeria together with commentaries by ten oil industry chief executives, vital petroleum statistics, reproductions of three relevant pieces of legislation and a number of business fact sheets.

Progressing Cavity Pumps

Henri Cholet (Éditions Technip, 27 rue Ginoux, 75737 Paris, Cedex 15, France). ISBN 2 7108 0724 6. 128 pages. Price: FFr 320.

The progressing cavity pump is a recent innovation in petroleum production. It has rapidly gained an important place in the production of heavy oils containing gas and is now often used in the production of large flow rates of light and abrasive oils. Driven by rod strings from the surface, it is a simple, rugged and cheap piece of equipment. The book provides clear and concise information related to the principles, qualities and performances of this system. It also lists the 'choice criteria' of a progressing cavity pump and the operational conditions for its implementation by technicians and field development managers.

Natural Gas in Latin America: Development and Privatisation

David Kurtz (FT Energy, Maple House, 149 Tottenham Court Road, London W1P 9LL, UK). ISBN 1 85334 750 7. 135 pages. Price: £350.*

Despite having proven reserves equal to that of North America, natural gas has traditionally played a minor role in the energy policies of Latin American countries, being considered secondary to oil. There is consequently no adequate gas infrastructure in the region, perhaps with the exception of Argentina. However, a massive increase in energy demand, coupled with growing environmental concerns and a need to reduce the massive pollution levels in many of the region's major cities, means that natural gas is forecast to play a much greater role in Latin America's energy profile with final consumption predicted to rise at 5.4% per annum over the next 15 years. This book analyses the possibilities and pitfalls of investing in the sector and describes the key trends and issues. It analyses all aspects of the gas industry from exploration, through production to transportation and distribution, to end users.

*A £100 discount is offered if purchased together with *The Oil Industry in Latin America: Changing Demand Patterns and Deregulation,* ISBN 1 85334 755 8, which is also priced at £350.

China Natural Gas Report

(Available from China OGP, Home News for Overseas Service Dept, Xinhua News Agency, 57 Xuan Wu Men Xi Da Jie, Beijing 100803, China). Price: $780 per copy (discounts offered – 2 reports: $1,260; 3 reports: $1,560).

This joint report from China OGP, Xinhua News Agency and the Energy and Environmental Programme, Royal Institute of International Affairs provides an in-depth guide to the Chinese natural gas sector which is playing an increasingly important role in the country's energy market. It identifies prospective investment opportunities and lists key data from China OGP, the only government-authorised information body in China. The report also details the government's plans for a transnational gas import pipeline linking Russia and Central Asia to China and gives supply and demand projections up to 2010.

Towards a Competitive European Natural Gas Market

(Available from Standard & Poor's DRI office, 11–13 avenue de Friedland, 75008 Paris, France). 267 pages. Price: $14,000.

This study concludes that the deregulation of western Europe's natural gas markets will lead to an almost doubling in the region's gas consumption by 2020. It also forecasts that vastly increased competition between both existing and new companies operating within this growing market will result in sweeping changes across Europe. Russia, Algeria and Norway are identified as principal future gas suppliers to western Europe over the next two decades and are forecast to contribute almost two-thirds of Europe's gas requirements by 2020. In addition, companies such as Gazprom in Russia, Algeria's Sonatrach and Statoil of Norway are expected to develop their own gas related distribution services to further secure their markets. Regulatory changes, implemented as part of the drive to deregulate Europe's gas market, are expected to significantly impact the profits of monopolies such as Ruhrgas (Germany), Distrigaz (Belgium) and Snam (Italy). Germany, France, Italy, Spain and Portugal are identified as markets with the greatest performance potential in a fully liberalised gas market while Finland, Sweden and Switzerland, where additional annual demand growth is small and margins are low, have the least potential.

LPG Shipping: Refocusing on Growth

(Drewry Shipping Consultants, Drewry House, Meridian Gate – South Quay, 213 Marsh Wall, London E14 9FJ, UK). 198 pages. Price: £450 (incl p&p).

This report contends that sustained trade growth, restrained ordering and the close relationship between ship owners and charterers will stimulate an increase in LPG carrier freight rates through the end of the decade to an anticipated market peak in 2002/3; at which point freight rates are predicted to be around 50% higher than those prevailing in the first eight months of 1997. Reviewing developments in the LPG shipping sector during the 1990s, the report also provides a wealth of statistical supply and demand information and seaborne trading figures.

Rock Mechanics: Petroleum Applications

Philippe A Charlez (Éditions Technip, 27 rue Ginoux, 75737 Paris, Cedex 15, France). ISBN 2 7108 0586 3. 704 pages. Price: FFr 780.

This second volume focuses on three major themes: drilling-well activities, hydraulic fracturing and reservoir engineering. It provides an overview of thermoporomechanic fundamentals and looks at borehole stability in poroelastic rocks, with particular attention devoted to drilling in highly tectonic regions. Well start-up is discussed together with an assessment of the concept of pore pressure/deformation coupling. Two chapters are devoted to hydraulic fracturing, including details of innovative applications such as stress measurements, drilling cuttings reinjection, acid fracturing and thermal induced fracturing related to water injection. The latter half of the book covers non-linear anelastic phenomena such as borehole stability in plastic rocks, production of poroplastic reservoirs, effect of compaction on recovery, sand production and casing collapse in salt formations.

Privatising European Energy: Policy Developments and Progress

Richard Milner (FT Energy, Maple House, 149 Tottenham Court Road, London W1P 9LL, UK). ISBN 1 85334 880 0. 143 pages. Price: £350.

This report analyses recent and proposed privatisation schemes in individual states and examines their impact on Europe's electricity, gas and oil markets. It emphasises the importance of the European Commission in the drive towards deregulation and privatisation and examines influential policy developments. Overviews of the electricity, gas and oil markets are provided on a country-by-country basis, with the UK used as a specific case study. There are also profiles of utilities earmarked for privatisation, such as Eni, Neste and Repsol.

Membership News

NEW MEMBERS

Mr G Bosinceanu, Histria Ship Management SRL
Miss R Brown, Wood Mackenzie Consultants Limited
Mr J A Cameron, NERA
Mr A R Campbell, Sharjah Oil Refinery Company Limited
Mr A P Cheesman, Gibb Limited
Mr I Doloshickij, JSC Naftotiekis
Mr A C Dorward, James Walker & Company Limited
Mr M J Dudley, Kuwait Petroleum (GB) Limited
Mr B Ekengren, Bertel Ekengren Limited
Mr C Eren, Saybolt-Catoni Turkey
Mr J A Fitzgibbons, Berkhamsted
Mr D J Fleisig, HAZEX Limited
Mr A Golovteev, Regional NeftInvest
Mr S N Goodman, Pinland Limited
Mr T M Green, Industrial Research Bureau
Mr R Hardman, Amerada Hess Limited
Mrs E Harper-Lawson, J&H Marsh McLennan Limited
Mr G Hartnell, Bechtel Consulting
Mr G Hewitt, Carshalton
Mrs S Hudson, ANZ Investment Bank
Dr T Idemudia, Nigerian National Petroleum Corporation
Mr N Kazarian, Regional NeftInvest
Mr I A Kennedy, HEV Limited
Mr R P King, Caltex Petroleum Corporation
Mr P J Kirton, Geolink (UK) Limited,
Mr J Kitto, Kuwait Petroleum (GB) Limited
Mr D Kotler, Lazard Brothers & Company Limited
Miss C H Mabilat, TOTAL Oil Great Britain Limited
Mr C McGibbon, British Steel SP & CS
Mr M P Mottershead, Cleethorpes
Mr K P Njeleka, Zambia National Oil Company
Mr T Nurekonov, Karazhanbasmuna
Mr P O'Mara, Karazhanbasmuna
Mr D Owei, Nigerian Agip Oil Company Limited
Mr J R Peet, Isle of Man Government
Mr F P Peppino, Oxted
Mr C Poncia, C R Poncia & Co
Mr A Prexl, Germany
Ms L Rudakewych, Futures World News
Mr R C Rusen, Histria Ship Management SRL
Mr D D Sen, India
Mrs P Seppala, Bertel Ekengren Limited
Mr T R Sexton, Project Management Limited
Mr G R H Stocks, Gillingham
Mr A Stroud, Elf Oil UK Limited
Mr J T Verghese, ABB Lummus Global Limited
Mr T Wood, Twickenham
Mr A J Woodrow, London
Mr A Zhakeeva, Karazhanbasmuna

NEW STUDENTS

Mr N O Al-Marhoon, London
Mr M Bragg, Aberdeen
Mr G J Colville, Heriot-Watt University
Mr N M Robertson, Aberdeen

Around the Branches

A full listing of Branch Events is available on the IP website:

http://www.petroleum.co.uk

or, if you require further information please contact your individual Branch Secretary.

NEW CORPORATES

Fox Construction, Block 6, Units 25/26, Chapelhall Industrial Estate, Chapelhall, Airdrie, ML6 8QH, UK.
Tel: +44 (0)1236 754301 Fax: +44 (0)1236 764444

Representative: Mr S Brown, Quantity Surveyor
Fox Construction has specialised in the construction and refurbishment of all aspects of petrol filling stations since the company was formed. It deals with all the major oil companies.

United Storage, Athel House, 167 Regent Road, Liverpool L20 8DD, UK.
Tel: +44 (0)151 933 1010 Fax: +44 (0)151 933 7434

Representative: Mr G P Hansen, Sales & Marketing
United Storage operates terminals in the UK on Merseyside, Humberside and the Thames. The blending of liquids either in-line or in batches is also available. The company operates a fleet of road tankers under the name of Transtore. In order to minimise clients, supply chain costs, United Storage also provides a facility management service on clients' premises.

Ove Arup & Partners, 13 Fitzroy Street, London, W1P 6BQ, UK.
Tel: +44 (0)171 465 2301 Fax: +44 (0)171 465 2126

Representative: Mr John Roberts, Director
Arup Energy provides multi-disciplinary services focused entirely on energy sector companies engaged in upstream activities from exploration and extraction, to transmission and distribution.

Arup's objective is to help its clients exceed their business objectives by adding value through technical excellence, efficient organisation and personal service.

Arup Energy incorporates six core areas of the energy market:

- Offshore Oil & Gas
- Onshore Oil & Gas
- Power Generation
- Risk & Safety
- Energy Consultancy
- Special Industrial Structures

Integrated project teams of engineers and specialists provide a complete range of in-house skills. Arup Energy's reputation for innovation and the development of cost effective solutions has established the company as a leader in its field.

As part of Ove Arup & Partners, one of the largest independent firms of consulting engineers in the world, Arup Energy can draw on the resources of over 5,000 staff working in more than 60 offices worldwide – allowing Arup to offer a global service locally.

Monde Petroleum SA, 5–6 Ransome's Dock, Parkgate Road, London SW11 4NP, UK.
Tel: +44 (0)1932 852055 Fax: +44 (0)1932 853525

Representative: Mr Y Al-Fekaiki, Bus Director
Monde Petroleum SA is a specialist in information processing and venture facilitation. This involves brainstorming, conceptual studies, IT and software application services and market appraisal with the emphasis on economic determinants of commercial viability. The company can assist in most types of international development opportunities, from cargo trading, to refinery/blending rehabilitation/modernisation to down-hole field servicing. For more information, please contact the UK office or consult the 1997 issue of the *World Trade Journal.*

EVENTS Forthcoming

APRIL

6–8 **Amsterdam**
The Petrochemicals Industry: an Overview of the Technology Marketplace
Details: The Center for Professional Advancement
Tel: +31 20 638 2806
Fax: +31 20 620 2136

12–16 **Paris**
The Biennial Industrial Technology and Process Exhibition
Details: Comite des Expositions de Paris, France
Tel: +33 1 49 09 60 00
Fax: +33 1 49 09 60 03

13–17 **Jakarta**
Basic Seismic Interpretation Including 3-D
Details: OGCI Training Inc, US
Tel: +1 918 742 7057
Fax: +1 918 742 2272
e-mail: training@ogci.com

14–15 **Singapore**
Oil Blending
Details: SGS Redwood Services, Singapore Pte Ltd
Tel: +65 778 1550
Fax: +65 779 5805

14–18 **Staffordshire, UK**
Geoscience '98
Details: The Geological Society, UK
Tel: +44 (0)171 434 9944
Fax: +44 (0)171 439 8975
e-mail: conf@geolsoc.cityscape.co.uk

15–16 **Houston**
SPE/International Coiled Tubing Association Roundtable
Details: Dan Lipsher, Society of Petroleum Engineers, US
Tel: +1 972 952 9306
e-mail: dlipsher@spelink.spe.org

15–17 **Ghana**
Oil & Gas Africa 1998
Details: FSG MediMedia, UK
Tel: +44 (0)1638 743633
Fax: +44 (0)1638 743998

15–18 **Bath, UK**
Corrosion and the Environment
Details: Caproco International, UK
Tel: +44 (0)1480 407600
Fax: +44 (0)1480 407619

16 **Southampton, UK**
Emerging Markets for New Materials and Adhesives in the Marine Environment
Details: Offshore Technology Management, UK
Tel: +44 (0)1483 821543
Fax: +44 (0)1483 821544

19–21 **Qatar**
Oil, Gas and Petrochemicals in Qatar: Developments and Opportunities
Details: IBC Gulf Conferences, Dubai
Tel: +971 4 552500
Fax: +971 4 527455

20 **London**
Multinational Investment and Human Rights: Forging a Consensus
Details: The Royal Institute of International Affairs, UK
Tel: +44 (0)171 957 5700
Fax: +44 (0)171 321 2045

20–21 **London**
1998 North Sea Conference: The Infrastructural Challenges Ahead
Details: Emma Jackets, Petroleum Economist, UK
Tel: +44 (0)171 831 5588
Fax: +44 (0)171 831 4567
e-mail: petecon2@easynet.co.uk

20–21 **London**
Fuel Cell Technology: Producing 'Green Cars' at a Profit
Details: Anita Ferrari, IQPC, UK
Tel: +44 (0)171 691 9191
Fax: +44 (0)171 691 9192
e-mail: enquire@iqpcmail.co.uk

20–22 **Bahrain**
3rd Middle East Geosciences Conference and Exhibition
Details: Overseas Exhibition Services, UK
Tel: +44 (0)171 486 1951
Fax: +44 (0)171 486 8773
e-mail: oilexhibit@aol.com

20–24 **Paris**
International Petroleum Economics
Details: ENSPM Formation Industrie Economie, France
Tel: +33 1 47 52 72 93
Fax: +33 1 47 52 70 66

21 **London**
Environment Trade and Investment
Details: The Royal Institute of International Affairs, UK
Tel: +44 (0)171 957 5700
Fax: +44 (0)171 321 2045

21–22 **Stavanger**
FPSO-Norge '98
Details: OCS Technology Group, UK
Tel: +44 (0)1462 712049
Fax: +44 (0)1462 711889
e-mail: GroupOCS@aol.com

21–22 **Istanbul**
Mediterranean Gas Conference
Details: Overview Gas Conferences, UK
Tel: +44 (0)171 613 0087
Fax: +44 (0)171 613 0094

21–22 **London**
New Entrants in European Energy
Details: Rebecca Luing or Sarah Ritchie, IBC UK Conferences
Tel: +44 (0)171 453 2703
Fax: +44 (0)171 323 4298

22 **London**
Viable Field Tests for Contaminated Sites
Details: SCI Conferences, UK
Tel: +44 (0)171 235 3681
Fax: +44 (0)171 235 7743
e-mail:
conferences @chemind.demon.co.uk

22–23 **Bahrain**
Geo '98
Details: Arabian Exhibition Management WLL, Bahrain
Tel: +973 550033
Fax: +973 553288
e-mail: aeminfo@batelco.com.bh

22–23 **Aberdeen**
Managing Your Post-Inventory Year 2000 Project in the Oil and Gas Industry
Details: EuroForum, UK
Tel: +44 (0)171 878 6886
Fax: +44 (0)171 878 6885

22–23 **Washington DC**
The International Petroleum Forum
Details: The Petroleum Finance Co, US
Fax: +1 202 872 1219

22–25 **Marrakesh**
26th IRU World Congress – Road Transport, Driving Trade and Tourism
Details: International Road Transport Union, Switzerland
Tel: +41 22 918 27 00
Fax: +41 22 918 27 41

23–24 **Aberdeen**
Advances in Downhole Technologies
Details: IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858

23–24 **Houston**
Third Annual Gas & Electricity Trading Summit
Details: Global Change Associates, US
Tel: +1 914 949 6798
Fax: +1 914 948 5301
e-mail: 76111.424@compuserve.com

23–24 **Stavanger**
Floating Production Training Course
Details: OCS Technology Group, UK
Tel: +44 (0)1462 712049
Fax: +44 (0)1462 711889
e-mail: GroupOCS@aol.com

EVENTS Forthcoming

23–24 **London**
Transnet 98: Emerging Channels & Technology for Retail Financial Services
Details: Chiara Muzzi, Worldwide Business Research, UK
Tel: +44 (0)171 691 3000
Fax: +44 (0)171 691 3001
e-mail: transnet@wbr.co.uk

27–30 **Paris**
Project Leadership
Details: ENSPM Formation Industrie, France
Tel: +33 1 47 52 72 93
Fax: +33 1 47 52 70 66

26–1 May **Perth**
LNG Symposium
Details: The Alphatania Partnership, UK
Tel: +44 (0)171 613 0087
Fax: +44 (0)171 613 0094

27–30 **Bedford, UK**
Pumps and the Plant Design Engineer
Details: School of Mechanical Engineering, Cranfield University.
Tel: +44 (0)1234 754766
Fax: +44 (0)1234 751875
e-mail: dfei@cranfield.ac.uk

28 **London**
Eco-efficiency: Doing More for Less
Details: IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e-mail: cust.serv@ibcuk.co.uk

28–29 **Turkey**
Central Asian Republics Refining Roundtable
Details: World Refining Association (WRA).
Tel: +44 (0)1242 529090
Fax: +44 (0)1242 529060

29 **London**
National Industry Conference for Engineering Construction
Details: ECIA Conference Office, UK
Tel: +44 (0)1323 410146
Fax: +44 (0)1323 644904

29–30 **London**
Kazakhstan Oil and Gas
Details: EuroForum, UK
Tel: +44 (0)171 878 6886
Fax: +44 (0)171 878 6885

29–30 **London**
Legal & Practical Problems in Multimodal Transport
Details: IBC UK Conferences
Tel: +44 (0)171 453 2107
Fax: +44 (0)171 453 2117

29–30 **London**
Norway – Oil & Gas Industry Export Conference: Opportunities for the UK Oil and Gas Industry
Details: IBC UK Conferences
Tel: +44 (0)171 453 5494
Fax: +44 (0)171 636 6858

MAY

4–7 **Perth**
12th International Conference & Exhibition on Liquefied Natural Gas
Details: LNG 12 Conference Secretariat, Australia
Tel: +61 2 9262 2277
Fax: +61 2 9262 2323

3–7 **Singapore**
4th Intertanko Singapore Tanker Event
Details: Julia Hoerenz-Lisethe, Intertanko, Norway
Tel: +47 22 12 26 83
Fax: +47 22 12 26 41
e-mail: julia.hoerenz@intertanko.wwis.no

8–11 **Surrey, UK**
The Fundamentals of the Oil Industry
Details: Petroleum Economist, UK
Tel: +44 (0)171 831 5588
Fax: +44 (0)171 831 4567

10–12 **Dublin**
European Lubricating Grease Institute AGM
Details: Carol Koopman, ELGI, The Netherlands
Tel: +31 (0)20 67 16 162
Fax: +31 (0)20 67 32 760

11–12 **London**
Emerging Markets for Emissions Trading: Opportunities from the Kyoto Protocol and the Implications for Business
Details: Pauline Ashby, The Institute of Petroleum

11–13 **France**
International Refining Economics
Details: ENSPM Formation Industrie, France
Tel: +33 1 47 52 72 93
Fax: +33 1 47 52 70 66

11–14 **Oxford, UK**
Planning and Optimisation of Refinery Operations
Details: College of Petroleum and Energy Studies, UK
Tel: +44 (0)1865 250521
Fax: +44 (0)1865 791474

11–15 **Budapest**
Terminal Operation and Bulk Liquid Measurement
Details: Mike England, Abacus International, UK
Tel: +44 (0)1245 328340
Fax: +44 (0)1245 323429

12–15 **Budapest**
2nd International Pipeline Rehabilitation & Maintenance Conference & Exhibition
Details: Energy Logistics International, UK
Tel: +44 (0)1628 525492
Fax: +44 (0)1628 521928

12–15 **Frankfurt**
Power Plant Management, Operations and Maintenance
Details: IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858

13–14 **Bucharest**
5th Annual Central/East European Gas Conference
Details: Overview Gas Conferences, UK
Tel: +44 (0)171 613 0087
Fax: +44 (0)171 613 0094

17–21 **Aberdeen**
ConSoil '98
Details: Environmental Business Communications, UK
Tel: +44 (0)121 693 8338
Fax: +44 (0)121 693 8448

18–19 **Oxford, UK**
Fundamentals of Oil Refining
Details: College of Petroleum and Energy Studies
Tel: +44 (0)1865 250521
Fax: +44 (0)1865 791474

19–21 **Birmingham, UK**
Pipelines '98
Details: Donna McDowell, Pipelines '98, UK
Tel: +44 (0)171 505 6625
Fax: +44 (0)171 505 6600

20–21 **Aberdeen**
Progress in HP/HT Fields
Details: IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e-mail: cust.serv@ibcuk.co.uk

23–29 **Sydney**
AIEE '98
Details: Reed Exhibition Companies Ltd, UK
Tel: +44 (0)181 910 7743
Fax: +44 (0)181 910 7749

IP Conferences and Exhibitions

International Conference

Emerging Markets for Emissions Trading – Opportunities from the Kyoto Protocol and the Implications for Business

London: 11–12 May 1998

Sponsored by the United Nations Conference on Trade and Development (UNCTAD) and supported by the Department of Trade and Industry and the Department of the Environment, Transport and the Regions.

The year 2000 will see the creation of a new greenhouse gas emissions trading market which was agreed in principle at Kyoto in December 1997. This Conference will address the implications for energy providers of a new emissions market and assess the potential opportunities in emissions trading and joint implementation.

Speakers include: The **Rt Hon John Prescott MP** (subject to confirmation) Deputy Prime Minister, **Adair Turner** (Director-General CBI), **John Guinness** (Chairman, British Nuclear Fuels plc), Chris Moorhouse (Chief Executive, BP Oil International) and **Ken Newcombe** (Division Chief, World Bank).

The Programme and registration form is now available.

International Conference and Exhibition

Metalworking Fluids

Birmingham 3–4 June 1998

Organised in association with The British Lubricants Federation and PERA Technology

This Conference will provide a significant insight into the future development of the Metalworking Fluids market. Emphasis will be placed on the impact of legislation and environmental concerns and how these differ through the geographical regions of Europe. The Conference will not only focus on the fluids themselves, but will include sessions on machine tool design, novel methods of in-line analysis, new test methods and the future role of biocides.

Speakers include: **Pat Ruane** (Castrol Industrial), **Cliff Lea** (Fuchs Lubricants), **Bob Howard** (Polartech), **Dr Steve Mosley** (PERA Technology), **Dr Rob Walter** (IBS Viridian), **Wallace MacDonald** (Castrol Industrial), **Dr Ian Liddle** (Rolls-Royce), **Michael Kohut** (Lubrizol International Laboratories) and **Mikael Olsson** (Volvo Technological Development Corp).

The programme and registration form is now available.

Annual Introduction Courses

Introduction to Oil Industry Operations

London: Wednesday 17–Friday 19 June 1998 and

and

Introduction to Petroleum Economics

London: Monday 22–Wednesday 24 June 1998

The programme and registration form is now available.

International Conference

Aviation 2000 – Safety and Operations

London: 1–2 October 1998

There is increasing emphasis on Ramp Safety within the aviation industry, both in terms of fuelling questions and other ramp users. This topic, together with the new issue of the IP Aviation Model Safety Code will be fully reviewed. The new developments in filtration and related test procedures will also be discussed and linked with the broader issue of fuel quality impacts on jet engine performance. This important Conference will be of interest to all involved in aviation fuelling together with those with a broader interest in Ramp Safety. An Exhibition of equipment linked with aviation fuelling will be held in association with the Conference.

The programme and registration form will be available in May 1998.

For a copy of the programme and registration form for any of the above or to add your details to the mailing lists for forthcoming events, please write or fax:

**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**

All forthcoming events can be viewed on the IP web page: http://www.petroleum.co.uk

Diary Dates

Energy Economics Group

in association with London Oil Analysts Group (LOAG)

'Financing the Oil Industry'

Tuesday 21 April 1998, 17.00 for 17.30

Peter Nicol, Oil Equity Research Analyst, Goldman Sachs, and

Carol Bell, Oil Banker, Chase Manhattan Bank

IP Contact: Jenny Sandrock

Exploration & Production Discussion Group

'The Institutions of the European Union – a Way to the Federal State?'

Thursday 7 May 1998, 17.00 for 17.30 until 19.00

Eckhard Wiemann, Senior Advisor EU Affairs, Mobil Europe, Brussels

IP Contact: Jenny Sandrock

Midland Branch Luncheon

Wednesday 13 May 1998
Walsall Football Club, Walsall

Professor Stephen Littlechild,
Director General of Electricity Supply

For more information or to apply for an application form please contact:
Mr Mike Ward, IP Midlands Branch
Tel: +44 (0)1299 896654 Fax: +44 (0)1299 896955

All meetings are held at the Institute of Petroleum unless otherwise stated. Please tell the IP contact if you plan to attend any of these free meetings.
Tel: +44 (0)171 467 7100
Fax: +44 (0)171 255 1472

Q: Where can you find a News in Brief Service that is updated daily?

A: The Institute of Petroleum's website at

www.petroleum.co.uk

London Branch

'The Future of Packaging'

Thursday 14 May 1998, 18.00

Ian Robinson, Consultant, **Ian Dent,** BP Chemicals, and **Tony Hancock,** Plysu Containers

Current and proposed legislation, both in Europe and in other world areas, relating to the packaging of manufactured goods is having a major impact on industry. The presentations will examine the significance of packaging in the petroleum industry and the potential effects of this legislation on the marketing of petroleum products. A range of ecologically acceptable technical, environmental and political solutions to the problems raised, including the relative economics will be reviewed.

The presentation will be preceded at 17.30 by the Branch's Annual General Meeting.

Tea and biscuits will be served at 17.15.
Light refreshments will be available afterwards.
Enquiries: Mr J M Wood at the Institute,
Tel: +44 (0)171 467 7128

MOVES People

Exxon Corporation has elected **Timothy J Hearn** as Vice-President, Human Resources. He succeeds **Daniel S. Sanders** who will become Executive Vice-President, Exxon Chemical Company. The appointment is effective from 1 March.

Premier Oil plc has announced the appointment of **David John** as non-Executive Chairman, effective from 1 March. He succeeds **Sir Barrie Stephens** who retired at the same time.

Philip Rogerson, Deputy Chairman of BG plc has left the company a year earlier than planned. Rogerson, who was involved in the British Gas demerger has been compensated for his early departure. He will become non-Executive Chairman of Pipeline Integrity International, the company's pipeline inspection and service business.

BG plc has announced the appointment of **Sir John Coles** as a non-Executive Director, with effect from 1 March. Formerly, Permanent Secretary in the Foreign and Commonwealth Office and Head of the British Diplomatic Service, he retired from these posts in November 1997.

Sir James Hamilton has been named Chairman of Brown & Root Ltd. He has been a member of the Brown & Root Advisory Board since 1983 and succeeds **Basil Butler** who retired at the end of last year.

John Mumford **(right) has become Chief Executive of BP Oil UK, replacing *Chris Moorhouse* (below) who has taken charge of BP's international oil trading operation in London. Mumford joined BP in 1966, working in London, Australia and Thailand. For the past two years he coordinated the BP/Mobil joint venture in Brussels. Moorhouse will also become President of the Institute of Petroleum when David Setchell completes his two-year term in June.**

Amec plc has appointed the **Rt Hon Sir Richard Needham** as a consultant to the company's international business development strategy.

John Lander has been appointed Managing Director of Tuskar resources plc. He replaces **Emmet Brown**, who has resigned as Director of the company to pursue other opportunities. He was previously Executive Director of British-Borneo Petroleum Syndicate plc.

Marion Stern **has been appointed Associate Director of CMG. Stern will be responsible for the upstream oil and gas sector, and for developing the company's information management strategy for oil companies. She previously worked for Shell International.**

Chevron Corporation has appointed **Greg Matiuk**, Vice-President of Strategic Planning and Quality, to head the company's human resources and quality functions. **John Watson** will succeed Matiuk in his former role while Matiuk succeeds **Ron Kiskis**, former Vice-President of Human Resources, who was recently appointed to lead a new Caspian Action Team.

Arco Senior Vice-President **J B Cheatham** has been assigned to direct the company's E&P activities in Europe, Africa, the Middle East, Russia and other CIS nations. He will be based in London. **Stephen R Mut**, Arco Senior Vice-President will oversee the company's upstream activities in Latin America from headquarters in Caracas, Venezuela. He previously served as President of Arco Global Energy Ventures, based in Los Angeles.

Executive Vice-President **Robert Swanson** will retire from Mobil Corporation on 1 August after 40 years of service. Refining and Marketing Executive **Eugene Renna** is named as the company's new President and Chief Operating Officer.

J P Bryan has resigned as President and Chief Executive of Gulf Oil Resources Ltd. **Dick Auchinleck** has been named as new President and CEO. He also heads Gulf Indonesia Resources.

Gary Jones, **former President and CEO of TOTAL Petroleum North America, has been appointed Managing Director and Chief Executive of TOTAL Oil Great Britain Ltd with effect from 1 April. He succeeds *Philip de Boos-Smith*, who retires after six years in the position and a further 33 years with the TOTAL Group.**

The Neles Controls Group has appointed **Matti Kahkonen** to President of its Controls' Process & Energy Division. As President he will oversee the marketing and sales of products to the oil and gas, power, chemical and petrochemical industries. He is also responsible for the Helsinki Delivery Centre and Neles Controls' operations in Brazil.

Dr Bob Bell, Managing Director of SGS Environment for the past six years has now left the company. SGS is proposing to restructure its business subsuming its environmental consultancy business into its quality certification company.

Former Aston Martin Chairman **Victor Gauntlett** has been appointed to the Board of engine, lubricant and fuel testing specialist Biceri. Gauntlett is also Chairman and former owner of Proteus Petroleum, which was recently taken over by Texaco.

Jiskoot Autocontrol has promoted **Jon Moreau** to the newly created post of Marketing Manager. Moreau, who is responsible for marketing worldwide, has been Marketing Executive with the company for three years.

Dr Brian Abbott **will shortly be succeeding *John Hayes* as Technical Director at the Institute of Petroleum. Abbott is a geologist who joined Burmah Oil in 1973, subsequently working for Gulf Oil and Aminoil. In 1985 he joined Amoco and became Technical Director of Amoco Services in 1995. In 1996 Brian was appointed Director External Relations, US Exploration and Production Technology Group, which is the position he currently holds. He is expected to join the Institute sometime.**


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