Petroleum review

JUNE 1999

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover: Transocean's newly built *Discoverer Enterprise* drillship is capable of drilling, testing and completing wells of up to 35,000 ft in water depths up to 1,000 ft. Photo: Danny Faulkner

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From the Editor

Reducing drilling costs – the key to further non-Opec development

In the latest issue of its in-house magazine *Horizon*, BP Amoco explains how the use of through tube drilling allowed it to reduce the cost of a development well on the Forties field to \$2.5mn, compared with the \$4.5mn to \$6mn cost of a conventional infill well. The article also revealed that although the well tapped by the new technology was highly productive, the productivity of typical Forties field development wells has been declining from the 4,000 b/d range in the early 1990s to a relatively modest 1,600 b/d in 1997/98. It also noted that these recent low levels fall below the economic threshold.

It is clear that the underlying key to oil development in any mature province is to find ways of lowering drilling costs so that declining well productivities can be accommodated while maintaining profitable operations (see p34 describing well cost initiatives in the UK and details of an upcoming conference p35). The only other alternative is to abandon the field when wellflows fail to cover operating costs. Onshore very low flowrates can remain economically viable, although the requirement for a large expenditure such as a major workover may force abandonment. However, in the offshore environment the high costs of both day-to-day operations and development drilling mean that fields will almost certainly have to be abandoned while still producing at rates that would be highly profitable onshore.

Although well productivities tend to decline as a field is drilled up, there is always the possibility of pleasant surprises. The particular well described in the BP Amoco article accessed an untapped pocket in the field and proved highly productive with flow rates of around 5,000 b/d, the highest new well flows seen in the field for some years.

A useful rule of thumb is that for a development well to be undertaken it must recover its costs within 500 days or less. Using this logic a low-cost onshore well in Texas, say, which might cost \$100,000, would be justified if it produced oil worth in excess of \$200/d. If the oil price assumption or hurdle was \$10/b it would need to produce 20 b/d just to cover the drilling costs. All wells decline once brought onstream so to ensure that the money was recovered the required initial flow would need to be doubled. It therefore follows that around 40 b/d would be needed to justify drilling a \$100,000 well.

Although such calculations are necessarily broad-brush it does provide an indication of the sort of well productivities that are required for particular drilling costs. In the North Sea, if a typical platform based development well costs \$5mn it would need to produce an income of \$10,000/d, implying an initial flow of 1,000–2,000 b/d. The recent experience of low prices means that companies would be looking for initial flow rates towards the top end of this range. As the number of opportunities decreases and the required (economic) flowrates remain high, the need for lower cost drilling technologies (and initiatives such as Crine's 'Double the value of wells by 2000' project) is self evident.

Amid all the talk of increased investment in the low-cost production areas of the world there is little mention of the fact that with the exceptions of Angola, Mexico and Brazil average well productivities are now falling in every country in the world (see **Table 1**, opposite). Clearly declining well productivities matter in terms of maintaining supplies and in maintaining industry profitability. High flowrates are always more attractive than low flow rates and are the underlying determinant of industry profitability. There is clearly an urgent need for technologies that either enhance flowrates or reduce drilling costs. There is, however, one rather drastic remedy for high drilling costs – devaluation. Last year Russian development drilling was becoming increasingly uneconomic but following the devaluation it is now highly attractive despite generally low well productivities.

There are only two public sources for numbers of producing wells and associated production data. These are the annual surveys printed in *World Oil* and in the *Oil & Gas Journal*. *Petroleum Review* has calculated ranges of well productivities for a series of periods since the late 1960s (**Table 1**).

In addition to calculating well productivities by using data from *World Oil* it is possible to calculate the percentage of producing wells that are flowing naturally (not pumped) by region and country (see **Table 2**, p7). This shows a remarkably similar pattern to well productivities with declines in virtually all regions and major producing countries. Of the regions only western Europe is experiencing a rising proportion of flowing wells as a result of onshore abandonments and offshore development. In con-

Web World

The final countdown

The Millennium Bug will affect almost everyone in some form or another, and it can't simply be swatted. The Y2K problem is the result of the way in which computers and embedded systems handle the date. The bug manifests itself when the century changes and 99 becomes 00. Some systems will think this means 1900 rather than 2000. PCs represent only one aspect of the Y2K issue. Most will not do anything more dramatic than simply display the wrong date on 1 January. The majority of problems lie in the area of software and embedded systems.

The palpable smell of fear throughout industry has resulted in a deluge of websites that address the various issues. The British Computer Society (**www.bcs.org.uk/millen.htm**) includes details of relevant events, practical guides, articles, full-text resources and links to other sites.

Action 2000 (**www.bug2000.co.uk**), a Government-sponsored initiative, provides information and advice on preparing your business and home for the date change. There is also a rather worrying section on the millennium readiness of infrastructure sectors, such as electricity, gas and finance. Never mind, you still have six months to install solar panels on your roof and hide all your money under the mattress.

The British Standards Institution (**www.bsi.org.uk/disc/year2000.html**) publishes a document addressing Year 2000 conformity, with a definition of the expression and a list of the requirements that must be satisfied in equipment and products which use dates and times.

The Institution of Electrical Engineers website (**www.iee.org.uk/2000risk/**) details risk management techniques to 'assess and manage the risk to a company, or other organisation, which is posed by the possible Year 2000 failures in equipment and machinery'.

Unless you're one of the 0.00001% of people who don't use Microsoft products, you'll need to visit the site (**www.microsoft.com/technet/year2k**) to update your software. Here you'll find downloadable patches and a message from Uncle Bill to reassure us all that his products are compliant (once you've downloaded the patches that is).

Are you still afraid of the Millennium Bug? You could always visit Tesco (**www.tesco.co.uk**) to stock up on tinned food for your air-raid shelter.

You can find these links and more on the IP website (**www.petroleum.co.uk**) which is, of course, Y2K compliant.

If you have any questions regarding this issue, please contact Catherine Pope – **cpope@petroleum.co.uk**

Region/Country	Late 1960s	1970s	1980s	Early 1990s	Latest 1997/98
Middle East	4,200–4,600	5,200–6,200	4,500–2,200	2,200–2,500	1,800–1,950
Western Europe	60–70	100–350	400–600	700–800	950–1,350
Africa	1,200–1,900	2,000–1,200	900–1,100	1,000→900	850–900
Asia-Pacific	150–350	400–600	600–700	100→85	80–82
Eastern Europe/FSU	–	–	116→86	75→60	50–60
Western hemisphere	22–28	25–29	27→22	23–24	26
World	40–65	70–80	80→60	63–70	71–72
Opec	–	–	–	1,000–750	764
Algeria*	900–1,200	800–1,200	750–1,200	1,200–900	1,000
Angola	500–1,000	800–1,400	600–1,000	1,000–1,400	1,250–1,400
Australia	100–500	800–1,100	900→600	600→450	430–450
Brazil	140–160	160→100	100–140	95–115	115–120
Canada	50–60	60–80	60→35	32–36	32–36
China	–	–	85–60	43–46	43–44
Egypt	400–850	850–1,250	1,250→950	900→750	680–700
India	100–170	180–200	180–260	190–220	180–190
Indonesia*	200–250	420–490	400→220	200–160	160–180
Iran*	10,000–13,000	9,500–16,000	4,000–8,000	4,000–4,800	3,250–3,350
Iraq*	10,000–14,000	11,500–15,000	6,000–8,000	5,000–10,000	–
Kuwait*	4,400–4,600	2,500–4,200	2,100–4,000	2,300–2,900	2,200–2,300
Libya*	2,200–3,200	3,400→1,900	1,100–1,300	1,250→1,000	900–1,000
Malaysia/Brunei	150–220	500→650	550–750	750→550	550–600
Mexico	125–135	150→450	700–800	750–760	840–860
Nigeria*	1,200–2,000	1,450–2,800	800–1,300	1,020–1,150	1,020–1,120
Norway	–	3,000–8,000	4,800–6,500	6,700–5,500	5,200–5,800
Russia	–	80–100	80–110	70→55	58–60
Saudi Arabia*	7,100–7,250	4,000–13,000	14,000–5,000	5,800–6,000	5,500–5,700
UAE – Abu Dhabi*	5,500–6,300	5,500–9,000	3,500→1,500	1,600–1,750	1,560–1,650
UK	32–42	42–8,000	5,000–2,500	2,400–2,800	2,600–2,700
USA	13.5–20	19→16	16→12.5	12.3→11.5	11–11.2
Venezuela*	290–300	320→190	140–180	160–200	205–210

→ *steady trend; *Opec member*

Source: Oil & Gas Journal, World Oil, *calculations by* Petroleum Review

Table 1: Average oil well productivities in barrels per day for the 23 largest producers and by regions, 1965 to date

trast the Asia-Pacific region has experienced a very rapid decline over the last 20 years. Among the largescale producers there is an exclusive club of Middle East producers plus Norway where all or virtually all wells flow unaided. At the other end of the spectrum are countries such as Australia, Brazil, Canada, China, Indonesia, Russia, the US and Venezuela where less than 10% of wells flow unaided. Declines in recent years have been particularly notable in all these countries strongly suggesting that without significant cost reductions they will have difficulty maintaining flowrates.

When considering well productivities, averages over wide geographical areas need to be treated with some caution. However, the general trend to lower productivities is clear with the world average dropping from around 80 b/d in the 1970s and 1980s to around the 70 b/d today. Opec countries are roughly ten times as productive as the world average but the general decline applies to them as much as any other area. The only countries (Angola, Brazil and Mexico) and areas (western Europe) recording rises in well productivities are where high productivity offshore production is expanding.

Large declines are seen for the Asia-Pacific region and for Eastern Europe/FSU. The former has occurred despite free access to capital but lack of investment in new projects explains at least some of the rapid decline in the FSU. In the case of the Western Hemisphere the productivities are remarkably constant. The region is dominated by the vast number (nearly 600,000) of low productivity wells in the US that tends to bring the average down. The number of operating wells constantly changes with the least productive being closed or worked over and new ones being drilled. It may be that where well productivity figures are stable they represent the economic minimum commensurate with the risk profile of that country.

For other areas of the world all the various risks tend to be higher than in the US with each country or basin having its own unique and changing package of risks and rewards. In an important sense well productivities reflect this package of risks. Tax treatment largely determines the point when it is no longer attractive to expand production by drilling incremental wells. Geology, however, determines the basic productivity and accounts for the wide variations between countries and areas. It is the key constraint as to where there are drilling opportunities. In general geology will determine the attractiveness of a province but falling well productivities will determine the point when tax rates become insupportable, when production cannot be economically expanded and ultimately the point of abandonment.

In terms of the individual countries only Angola, Brazil and Mexico are still experiencing well productivity growth. In all three cases the reason is the opening up of large productive offshore fields. This contrasts with the experience of the two main North Sea producers, the UK and Norway, both of which are now experiencing declining average well productivities. In the case of Norway the decline is very recent and may even be reversed as new large fields come onstream. In the UK sector, however, the declining trend is well established and reflects the fact that recent field developments have been predominantly small with short-lived production peaks and limited reserves.

Since the late 1970s most producing countries and private companies have tended to operate their production assets at or close to capacity. As a result trends in well productivities reflect the state of depletion of the reservoirs. In contrast Opec producers have had

continued on p16...

NEWS Upstream

In Brief

World's largest deepwater drilling vessel

Transocean's *Discoverer Enterprise* – claimed to be the world's largest, most advanced drilling unit capable of drilling, testing and completing wells of up to 35,000 ft in water depths up to 10,000 ft – has been contracted to BP Amoco for five years and will be put to work in the Gulf of Mexico. The vessel is currently undergoing final outfitting at Ingalls Shipbuilding in Pascagoula, Mississippi.

The 835-ft long, 125-ft wide drillship features 'dual-activity technology' which, according to Transocean Offshore's Chairman and CEO J Michael Talbert, 'allows for simultaneous drilling activities, resulting in significant gains in terms of efficiency'. The company expects that the dual concept will cut well construction time and costs by as much as 40%.

The vessel's dual-activity capability is provided by two separate drilling areas set 40 ft apart on an 80-ft by 80-ft rig floor. Each is centred around a full-capability rotary table. Each rotary has its own top-drive, 5,000 horsepower drawworks and crown-mounted motion compensator. An automated pipe handling system – which has been designed with remote touch screen controls to minimise traditional roughneck 'hands on' work – allows drillpipe to be easily moved from either rotary to the set back areas.

'The drillship's dual-activity capability is designed to reduce well construction time by enabling operations to be conducted simultaneously, rather than sequentially,' comments Talbert. 'The dual-activity concept should also enable increased well construction quality, reduce non-productive time and allow the flexibility to perform a wide range of subsea operations, including the J-laying of ultra-deepwater pipelines.'

The forward work area is equipped with tensioners and will be used as the primary rotary for drilling through the riser and BOP (blow-out preventer) stack. The aft work area has been designed for riserless drilling operations and non-drilling subsea operations, although it could be upgraded to serve as a secondary primary rotary for drilling with its own riser and BOP stack. The aft work area can also serve as a staging ground for the preparation and testing of equipment to be utilised in the forward work area.

The vessel is capable of storing up to 125,000 barrels of produced fluids, as well as 12,000 barrels of drill water, 7,000 barrels of potable water and 36,000 barrels of fuel. This will allow the drillship to drill multiple wells before resupply of well consumables is required.

The installed well-test equipment is designed to handle flowrates to 20,000 b/d and 100mn cf/d of gas. Coupled with the large storage capacity for produced fluids, high flowrate or extended well testing is possible without the need for additional vessels to handle the produced fluids, the company points out.

Unocal and Chevron have also contracted for two additional Enterprise-class vessels – *Discoverer Spirit* and *Discoverer Deep Sea* – which are currently under construction for Transocean at the Astano shipyard in Spain.

United Kingdom

KCA Drilling has secured a contract from *Phillips Petroleum extending its current wireline workscope on the Maureen, Judy and Joanne North Sea fields to include Phillips' southern sector North Sea operations.*

Marathon has awarded Coflexip Stena *Offshore Ltd (CSOL) an EPIC contract as part of the fast-track development of the Kinsale gas field. The development plan comprises re-entering and completing the existing 48/25-3 discovery well which is to be tied back via an uninsulated 12-inch diameter rigid flowline to the Kinsale Bravo platform 7 km away.*

Environmental group Greenpeace has *won the right to challenge the UK government in court over its alleged failure to protect marine species from the impact of oil exploration in the Atlantic Frontier.*

KCA Drilling has signed an interim *agreement worth £200mn with Shell UK Exploration and Production to manage drilling operations on its nine Northern Business Unit (NBU) platforms in the North Sea over the next five years.*

Phillips Petroleum has awarded Amec *Process and Energy a contract to carry out the front-end engineering design (FEED) for the development of its North Sea Jade field.*

Talisman Energy's Ross field in the *Outer Moray Firth has come onstream. Field reserves are put at 60mn barrels of oil and between 20bn and 30bn cf of gas.*

Lasmo has sold a package of southern *North Sea assets to Gaz de France for more than £90mn. Assets sold include Lasmo's interests in the Caister, Boulton, Hunter, Chiswick and Cavendish fields, as well as its stakes in the Caister Murdoch and Eagles Transportation pipeline systems.*

Europe

TOTAL (8.17%) and partners *Wintershall (6.2%), EBN (50%) and NAM (35.63%) have brought onstream the Andalusite gas field in blocks D15 and D12a offshore the Netherlands. Production is expected to reach 1bn cmly of gas.*

Aviation first for emergency response offshore UK

Briggs Marine Environmental Services has launched what it says it the UK's first commercial aerial response service to deal with offshore oil pollution. The company has invested over £750,000 in its new Inverness-based operation.

Two aircraft, hired from Air Atlantique, will be on permanent standby at Inverness airport, offering all-weather support both day and night to manage pollution incidents.

A dedicated surveillance aircraft – a Cessna 402 – has been fitted with state-of-the-art monitoring technology, including video and infra-red imaging and data transmission equipment, and can relay oil spill data directly to Briggs Marine's control centre in Aberdeen and to the on-location emergency response teams of the company involved in the incident.

The service is currently available only to the 11 UK Oilspill Response Club members co-funding the initiative: Arco, BP Amoco, Conoco, Elf Exploration, Kerr McGee, Marathon Oil, Phillips Petroleum, Talisman Energy, Texaco, Veba Oel and Wintershall.

World drilling record

Total Austral is reported to have broken the world record for extended reach drilling it set with well CN-1 in January 1999 in Tierra del Fuego, Argentina, by drilling a second drain in the same well in March.

The new drain extends the world record for horizontal displacement to 10,585 metres at 1,656 metres TVD (total vertical depth).

The CN-1 well also holds the world's measured depth record for a commercial well at 11,184 metres.

Faroes agreement

The governments of the UK, Denmark and the Faroe Islands have signed an agreement establishing the continental shelf boundary between the Faroes and Scotland, ending a protracted dispute which has prevented the award of exploration licences on either side of the disputed boundary. The first licensing round for concessions in Faroese waters is expected later this year.

An agreement was also reached on the boundary for fishing rights which leaves existing patterns largely unchanged.

Borg development plan

Saga Petroleum is reported to have submitted a development plan for the small North Sea Borg field to the Norwegian government. Development of the Borg field – located in block 34/7 close to the Tordis field and formerly called H-Central – is expected to cost £70mn. Field reserves are put at 75mn barrels with first oil due in July.

Phase one development is planned via the nearby Tordis subsea installation to the Gullfaks C platform for processing and offloading. Other tie-in solutions may be used for the second phase of the project which could increase production from 15,000 b/d to 30,000 b/d by 2001.

Hibernia output revised

Hibernia's 1999 production target has been revised to 40mn barrels of oil. Current output averages between 100,000 and 120,000 b/d when Hibernia is injecting gas. This is expected to rise to between 135,000 and 140,000 b/d once a second gas compressor becomes available later this year.

A second gas injection well – which will provide additional flexibility for the field's gas injection programme – is currently being drilled and is expected to complete in July/August.

The Hibernia field has five oil producing wells in operation at present. A sixth is currently being drilled and is expected onstream later this year.

UK gets tougher on safety offshore

The UK Health and Safety Executive's Offshore Safety Division has begun an initiative aimed at raising awareness of the requirements for reporting injuries occurring offshore. The initiative is prompted by concerns that current working patterns in the sector may, in some circumstances, contribute to non-reporting of injuries which are legally reportable. For example, an injury occurring on the day before an offshore tour ends, resulting in a worker being unfit for normal work for the next three days (or more) is reportable, even if the worker is on leave, field break or otherwise not at work.

To help the offshore industry understand its reporting duties, HSE has published a revised leaflet which gives guidance on complying with the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR). It has also issued an Operations Notice which clarifies the requirements for reporting 'over three days' injuries.

In Brief

Elf Petroleum Norge has awarded a *contract to the WEB Platform Brokers to provide brokerage services for the five-year old Froy platform as well as the Lille Frigg and East Frigg subsea facilities. The platform and subsea facilities are due to be made available for re-use in 2000/2001.*

Elf Petroland has announced a new *gas discovery in the Dutch sector of the North Sea. The K5-11 discovery well flowed at 750,000 cm/d of gas. Studies are underway to define the most cost-efficient field development.*

North America

Chevron is reported to have made a *major gas discovery in the south-western area of Canada's Northwest Territories. The find near Forth Liard is estimated to contain between 400bn to 600bn cf of gas with potential production put between 70mn and 100mn cf/d (approximately 10 times the average rate of production from Canadian wells). First production is proposed in May 2000.*

BHP (50%) and Chevron (50%) are *planning to bring their Typhoon Gulf of Mexico discovery onstream by July 2001.*

Mariner Energy is understood to be *planning to sell a majority interest in the $70mn Pluto deepwater project in the Gulf of Mexico. The company is expected to retain between 35% and 40% interest in the field. Field reserves are put at 10mn boe with first production due in 4Q1999.*

BP Amoco has secured a key permit *from the US Army Corps of Engineers that will allow it to construct a subsea pipeline to its 130mn-barrel Northstar oil field on Alaska's North Slope. Agreement for the six-mile pipeline will enable the oil company to keep to its scheduled field start-up in late 2001.*

Titan Exploration is reported to have *sold its Gulf of Mexico assets to Coastal Oil and Gas Corporation for $71.3mn in cash plus various overriding royalty interests.*

Apache Corporation is to acquire a *number of oil and gas assets located on the outer continental shelf of the Gulf of Mexico from Shell for $715mn in cash and 1mn shares of Apache common stock.*

Industry confidence boosts oil prices

Expectations of a rise in oil prices after April have already boosted the figures for March, with Brent rising by almost 23% to $12.54/b, according to the latest figures from the Royal Bank of Scotland's *Oil and Gas Index*.

Production cuts agreed by Opec were not implemented until the beginning of April and will take some time to affect the balance of supply and demand, says the Royal Bank of Scotland. However, confidence that the cuts will stick has prompted the price rebound and resulted in a 24% increase in UK daily oil revenues. Average daily oil revenues in March stood at £20.6m, the highest level since May 1998. Since then, prices have continued to rise, reaching a high of $17 in early May.

'The rise in prices will bring welcome relief to operators and boost profitability and cashflows,' comments Stephen Boyle, Head of Business Economics at the Royal Bank. 'However, it is not sufficient to boost UK offshore investment this year.'

Gas revenues were down by 3.7% on the month, although year-on-year figures show an increase of 5.6%. Estimates for combined revenues show a 9.2% rise on the month and a 2.8% rise since March 1998. Oil production fell from just under 2.68mn b/d in February to 2.65mn in March. Gas production fell by 3.7% over the month, but rose strongly over the year by 13.3%. Combined oil and gas output fell on the month by 2.2% but rose over the year by 6.5%.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Mar 1998	2,595,594	9,803	13.17
Apr	2,571,241	8,844	13.53
May	2,433,059	6,381	14.40
Jun	2,406,521	6,069	12.12
Jul	2,432,040	5,733	12.06
Aug	2,379,644	5,640	12.05
Sep	2,573,882	6,394	13.28
Oct	2,600,813	8,832	12.60
Nov	2,612,843	10,738	11.07
Dec	2,715,056	11,123	9.81
Jan 1999	2,664,121	11,532	11.16
Feb	2,678,138	11,532	10.20
Mar	2,647,295	11,107	12.54

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Corrib drilling underway

Enterprise Oil's *Sedco 711* drilling rig arrived offshore County Mayo, Ireland, on 30 April to begin its 1999 drilling programme of the Corrib gas field. Almost £20mn is to be spent by Enterprise and partners Statoil and Saga Petroleum on the drilling of an appraisal well and exploration well.

The Corrib field – which is located in 1,150 feet of water, approximately 40 miles west of Achill Island, County Mayo – is believed to be at least two-thirds the size of the Kinsale field.

John McGoldrick, Area Manager for Enterprise Oil in Ireland, indicated that locations for bringing a possible gas pipeline ashore are under consideration and that Enterprise was interested in entering the Irish gas market, but that it would be the end of the year before the preferred options are known.

UK double for Amec

BP Amoco has awarded Amec a major contract for the provision of engineering and modifications support services to a number of business units within its UKCS portfolio. The contract covers the Bruce and Miller platforms, the Forties pipeline system, the company's southern North Sea gas fields and terminals, Sullom Voe oil terminal, the Wytch Farm onshore oil field, and the Harding platform.

The five-year contract – which virtually doubles the amount of work that Amec is undertaking for BP Amoco in the upstream sector – is based on Crine offshore terms and conditions and will be subject to regular performance reviews against agreed measures. Both parties have agreed to decouple profit from turnover in the interest of achieving sustained cost reduction.

In Brief

Conoco and Ocean Energy report that *they have discovered oil in the deepwater Magnolia prospect in Garden Banks block 783 in the Gulf of Mexico.*

Russia & Central Asia

Commonwealth Oil & Gas has *acquired Union Texas Qobustan's 40% stake in the exploration, development and production sharing agreement for the southwest Gobustan concession in Azerbaijan, doubling its overall interest to 80%. The remaining 20% is held by state-owned Socar. The onshore concession comprises three blocks, including 15 identified oil and gas structures, and is estimated to hold recoverable reserves of at least 100mn barrels of oil and 0.5tn cf of gas.*

Exxon and Socar have agreed explo- *ration, development and production sharing terms for the Zafar/Mashal offshore exploration block in the Azeri sector of the Caspian Sea.*

Russia's President Yeltsin has signed a *production sharing agreement law for the Kirinsky block (part of the Sakhalin 3 project).*

Tomskgaz, a 50:50 Gazprom/Eastern Oil *Company joint venture is understood to be planning to commence gas production from the Myldzhino field in the Tomsk region of Russia in May at an initial rate of 5bn cm/d. Output is expected to reach 25,000bn cm/d by 2005.*

US companies Exxon, Mobil and *Moncrief Oil International are reported to have signed production sharing agreement contracts worth $10bn covering the development of oil resources from the Azeri sector of the Caspian Sea.*

The Russian government has proposed *adding the Tyansk oil field to the list of fields eligible for development under the country's new production sharing agreement legislation. Tyansk reserves are put at 241.5mn tonnes of oil.*

Elf Petroleum Azerbaijan is reported *to be planning to drill four exploration wells on the Lenkoran/Talysh offshore blocks in the Azeri sector of the Caspian Sea. Drilling is due to begin at the end of 2000. Recoverable oil reserves are put at between 100mn and 110mn tonnes.*

NEWS Upstream In Brief

Bashneft, Tyumen Oil, Alfa-Eco and *TOTAL are to jointly develop the Kirsko-Kottynskoye oil field in Western Siberia. Field reserves are put at between 30mn and 50mn tonnes of oil.*

Burren Energy of the UK and Russia's *Tarasovskneft oil company are understood to have announced plans to jointly develop the Leonov oil and gas field in the Tarasov district of Russia's Rostov region. Reserves are put at 53mn tonnes of oil and 376mn tonnes of gas.*

Asia-Pacific

Exxon is understood to have agreed to *integrate its Hides gas field in Papua New Guinea with Chevron's nearby Kutubu gas field. It is thought that the move will help progress construction of a proposed $5.5bn gas pipeline linking Papua New Guinea to Queensland, Australia.*

The East China Sea Pinghu oil and gas *field is reported to have come onstream. The field is currently supplying 400,000 cm of gas to Shanghai, a figure expected to increase to 1.2mn cm/d within the next year.*

Premier Oil has acquired the Dadhar *exploration block in the gas-rich Baluchistan area of western Pakistan. Premier Exploration Pakistan holds a 95% interest in the block, the remaining 5% held by Government Holdings.*

Latin America

Petrobrás is understood to have *handed back 28 exploration areas offshore Brazil to the National Petroleum Agency (ANP). Petrobrás is also reported to be planning to bid, alone and through partnerships, for a number of areas out of a total of 27 fields to be auctioned by the National Petroleum Agency in June.*

Africa

BG Egypt (50%, field operator) and *partner Edison International (50%) have announced a new gas discovery following the successful testing of an exploration well in the West Delta Deep Marine concession in Egypt. The WDDM-5 (P12/P13) well tested at 45mn cf/d.*

Arco and partner Sasol are under- *stood to have agreed to carry project partner Zarara Oil and Gas's $3mn share of the $64mn investment required for the Temane gas project in Mozambique over the next 12 months.*

BP Amoco is understood to be *planning to dispose of its interests in seven exploration licences offshore Nigeria having spent $250mn over the past six years during which it made no major finds.*

Region/Country	Late 1960s	1970s	1980s	Early 1990s	Latest 1997/98
Middle East	70–78	65–80	37–64	55–60	52
Western Europe	3–10	9–14	9–16	17–28	29
Africa	68–75	72–62	64→38	37–39	57
Asia-Pacific	23–33	22–32	34→11	7–15	5
Eastern Europe/FSU	–	–	–	7.5–7	7
Western hemisphere	12→10	10→7.5	6.5–7.5	10–6	5.5
World	12.5→11	11→8.5	7.5–9.5	11–7	7
Opec	–	–	–	–	–
Algeria*	95–98	97–70	85–75	75	73
Angola	80–90	35–42	35–45	35–40	45
Australia	95–50	18–29	25–50	30→8	6
Brazil	45–30	10–12	12→7	6.5→5	5
Canada	18–20	19–20	19–21	20→10	10
China	–	–	38→8	7→3.5	3
Egypt	25–20	43–25	15–20	14–18	17
India	45–90	22–90	30–35	33–44	23
Indonesia*	18–22	15–21	19→12	11–15	7
Iran*	100	97–100	100	100	100
Iraq*	97–100	97–100	98–100	100	–
Kuwait*	100	98–100	95–100	100	100
Libya*	40–75	44→33	39→47	50–60	65
Malaysia/Brunei	12–20	22→45	35–45	35–40	36
Mexico	55→45	45→35	42–47	38–43	37
Nigeria*	100	97–100	80–85	80–85	83
Norway	–	100	100	100	100
Russia	–	?	?	8→7	7
Saudi Arabia*	100	100	100	100→93	93
UAE – Abu Dhabi*	100	100	90–100	90→86	86
UK	2–4	5→75	68–71	68→62	58
USA	11→9	9→6.5	6.5→5.5	5.5→3.5	4.8
Venezuela*	20–22	21→18	12–18	12→8	8

*→ steady trend; *Opec member*

Source: World Oil, *calculations by* Petroleum Review

Table 2: Percentage of wells flowing naturally for the 23 largest producers and by regions, 1965 to date

Linked solutions from Arthur Andersen and J D E

The enterprise business software provider J D Edwards recently concluded a formal alliance with consultant Arthur Andersen to provide services to energy and chemical companies.

Jim McLoughlin, Vice President and General Manager Energy & Chemicals at J D Edwards told *Petroleum Review* that the company had been working with Arthur Andersen since 1984, but that the formal link will strengthen the development of flexible solutions for the energy and chemicals industries at a time of very rapid change. At the same time J D Edwards was also announcing the general availability of its Energy and Chemicals Solutions (ECS) suite within the latest version of OneWorld™, the company's multi-platform, enterprise software suite. As part of this solution, more than ten ActivEra solutions will be focused on the needs of the energy and chemicals sector.

McLoughlin explained that the major technological edge the company's solutions offered was the ability to make rapid changes after implementation and the fact that the solutions could be run on a wide variety of platforms. He explained that by using simple business activators – similar in operation to the 'wizards' found in Microsoft programs – it had made changing the business process simple and straightforward for the user. This gave the system 'adaptability once built' and is what made it 'so powerful'.

The OneWorld product with the Energy and Chemicals Solutions has been shipped since January 1999. McLoughlin noted that backwards compatibility is extremely important: 'We can't desert companies who have been customers' as 'protection of investment is fundamental' to a continuing relationship. For the same reasons, he claims the architecture is 'the most open we could make' to give 'lifetime cost advantages'.

He also noted that there were currently five large enterprise systems companies – J D Edwards, IBM, Oracle, Peoplesoft and SAP – and that his company's ambition was to be first or second in the market. The route to this was more partnering like the link-up with Arthur Andersen.

Richard Emerton, a partner in Arthur Andersen's London office explained that Energy is one of three key business areas for his company. He went on to explain that the pressures on companies' cost bases meant that 'previously unthinkable' outsourcings were occurring as companies were now in a 'perpetual revolution/upheaval' which was 'biting into core competencies.

He went on to explain that as companies moved towards becoming 'virtual organisations; there was a need to become 'responsive'. It had become apparent to Arthur Andersen that the 'rigidity and inflexibility of existing information structures' was inhibiting responsiveness to changing circumstances. A six-month search, started 18 months ago, had identified J D Edwards' OneWorld software as the easiest to change, leading directly to the alliance between the two companies.

Provisional UK energy stats released

The UK Department of Trade and Industry recently released provisional statistics for UK energy production and consumption, together with petroleum product prices, for the 1Q1999.

Production of indigenous primary fuels in 1Q1999, at 80.4mn toe, was 4.4% higher than in the corresponding period a year ago. Production of coal fell by 12.0%, while production of oil, gas and primary electricity rose by 3.7%, 10.5% and 1.7% respectively. Total inland consumption of primary fuels, which includes deliveries into consumption, at 66mn toe, was 1.6% higher than that recorded for the same period a year ago. Consumption of gas and primary electricity rose by 10.2% and 0.8% respectively, while consumption of coal and petroleum fell by 13.6% and 1% respectively.

Compared with a year earlier gas use at power stations was up by over 15% while coal use at power stations fell by a similar proportion.

Total use of petroleum, including non-energy use, was 20.3mn tonnes, 1.4% lower than a year earlier. Energy use was slightly lower (down 0.9%) while non-energy use was a little higher (up 0.7%). Total motor spirit deliveries were 3.9% lower, but deliveries of unleaded gasoline were 5.0% higher. In the period, unleaded gasoline deliveries represented 83.1% of total motor spirit deliveries, compared with 76% a year earlier. Diesel fuel deliveries decreased by 1.2% while deliveries of other gas diesel oils, primarily used for heating purposes, decreased by 2.4%. Fuel oil deliveries fell by 10.1%, continuing its decline as a source of energy for industry and electricity generation. Deliveries of other products increased by 7.5%, due to increased deliveries of aviation fuel and burning oil.

United Kingdom

***BP Amoco Chief Executive John** Browne warned of possible further job losses above the 10,000 planned by year-end as he announced a 47% fall in 1Q1999 profits to $677mn. Details of additional cost savings are expected to be outlined in July.*

***Paladin Resources is reported to be** discussing a possible £220mn merger with Premier Oil.*

***Shell has posted what it calls 'encour**aging results' for the 1Q1999. Results on an adjusted CCS earnings basis were $1,436mn, 26% lower than a year ago, mainly due to lower crude oil prices and gas realisations, and the effects of reduced chemical, refining and marketing margins. Reported net income for the period was $1,678mn, only 1% lower than a year earlier.*

***British Gas reports that 1Q1999 total** group operating profit rose to £683mn from £572mn compared with the same period a year earlier. Transco's profits rose by £86mn to £551mn while BG Storage's profit fell by £13mn to £2mn.*

***UK oil companies, offshore gas pro**ducers and coal distributors are on track to avoid any significant disruption to supplies due to the Year 2000 threat to computer systems, according to independent assessments commissioned by the UK Department of Trade and Industry.*

Europe

***Norsk Hydro has launched a $2.23bn** takeover bid for Saga Petroleum. If successful, the merger would increase Norsk Hydro's proven reserves by 61% to 2,275mn boe and current production levels by 70% to 458,000 boe/d, and make it the second largest company in Norway after Statoil. It is reported that the merger could result in annual costs savings in the region of $130mn.*

***Kvaerner has posted a record 1Q1999** loss of $635mn.*

***UtiliCorp United Inc reports that its UK** and European operations will now operate under the name Aquila Energy.*

***TOTAL has posted a 1998 net income** before non-recurring items of euro1.05bn (FFr6.9bn) compared with euro1.16bn (FFr7.6bn) the previous year.*

Monument-al takeover bid from Lasmo

Lasmo has made a £600mn takeover bid for Monument Oil & Gas after pulling out of merger negotiations with Enterprise Oil. The offer comprises three new Lasmo shares for every seven Monument shares.

Cost savings of between £6mn and £7mn per annum are expected as a result of combining operations.

The companies state that the merger will create 'a leading E&P company with low cost reserves, strong growth potential and high quality cashflow'.

The combination exploits a strong overlap between the companies' core geographical business areas. Specifically, the companies believe the merger will:

- strengthen the enlarged Group's UKCS position;
- deliver operational and marketing synergies in Pakistan;
- enhance the potential of Monument's Caspian business;
- reinforce Lasmo's focus on the Middle East; and
- extend the scope and potential of Lasmo's North African position.

Tony Craven-Walker, Monument Chairman, has turned down an offer to join the Lasmo Board, but is reported to have said that he is not against the merger.

Tim Eggar, former Conservative Energy Minister and Monument's Chief Executive is to become a Lasmo non-Executive Director.

Redundancies are expected.

Watching the weather

Up to 50 years of historical weather data will be made available through the Saladin Information Service (SIS) from 30 June 1999, the global energy information company recently announced. From this date, Saladin clients will have access to global, quality-checked historical weather data from Earth Satellite Corporation (EarthSat), a world leader in value-added weather services for energy markets.

James Perry, Saladin's Managing Director, told *Petroleum Review* that the provision of SIS weather data was the direct result of extensive contacts with clients. Users, particularly those trading gas, electricity and gas oil futures, had identified weather data as the information they would most like to have, but noted that any series shorter than 30 years would be of only limited use. Perry stated that Saladin was particularly pleased to have secured high quality data for the last 50 years and anticipated that it would attract considerable interest and allow the company to sell its data services to a whole new group of users.

SIS will be delivering weather history, actuals and forecasts of up to one year from EarthSat's extensive database. The data will also include weather parameters such as temperature, precipitation, wind speed, relative humidity, % sunshine, heat index, wind chill index, and cooling and heating degree days for US and European weather stations.

Saladin's PAWS and EnergyServer solutions will enable users to graph, correlate, analyse, compare and manipulate the weather data together with over 30 different information sources from SIS as well as their own proprietary data.

Gas industry awards

The UK Institution of Gas Engineers has presented six Gas Industry Awards in recognition of 'significant achievement in the "new" liberalised gas industry' and to 'acknowledge innovation'.

The IGE Gas Industry winners included Global Energy Associates which was named Support Organisation of the Year (sponsored by Transco) and The Hong Kong and China Gas Company which won the Company of the Year award (sponsored by The Society of British Gas Industries).

Chinese Russian interest

Chinese National Petroleum Company (CNPC) may take an interest in BP Amoco-controlled Rusia Petroleum, owner of the license for the Kovykta gas condensate field, reports the United Financial Group's *Russia Morning Comment*. It is crucial for the success of the project to get CNPC involved as China is the main potential market for the company's gas, comments UFG.

CNPC, BP and, at earlier stages, Sidanco, already spent over five years in negotiations. The main obstacle for CNPC was the insufficient level of reserves. The field contains 970bn cm of recoverable reserves, but requires at least 1,500bn cm to justify the $7bn development and pipeline construction costs.

It is not known whether the field has been re-explored or if CNPC's recent interest means it is simply being more aggressive in its investment plans for future gas supplies to China, says UFG.

In Brief

North America

***Consolidated Natural Gas is under**stood to have rejected an unsolicited takeover bid from Columbia Energy in favour of a $9bn lower offer from electricity group Dominion Resources.*

***Chevron and Texaco are reported to be** in discussions regarding the possible merger of their operations in a deal valued in excess of $100bn.*

***Arco has posted a 1Q1999 net income** of $165mn compared with $220mn for the same period a year earlier.*

***US gas-to-liquids company Syntroleum** has reported a 1Q1999 loss of $2.80mn on revenue of $0.77mn. This compares with a loss of $2.93mn on revenue of $0.39mn in 1Q1998 when Syntroleum was a privately held company.*

***Texaco has reported a 1Q1999 net** income of $199mn, compared with a 1Q1998 net income of $234mn.*

***Phillips Petroleum has posted a** 1Q1999 net income of $70mn, a 71% decrease from net income of $243mn for the same period a year earlier.*

***Chevron has posted a 1Q1999 net** income of $329mn, a fall of 35% from 1Q1998 net income of $507mn.*

Asia-Pacific

***The Philippine government is planning** to sell 35% of its ownership in PNOC Energy Development Corporation to a foreign partner as part of a privatisation programme.*

***The Thai Finance Ministry is reported** to be planning to sell its 12% interest in Esso (Thailand) as part of its privatisation programme.*

***International Petroleum Investment** Company of the UAE is understood to be planning to acquire a 50% interest in Hyundai Oil.*

***Mitsubishi Heavy Industries is reported** to have secured a $1bn contract from Petronas of Malaysia for the construction of up to six new LNG carriers.*

Latin America

***The Board of Argentinian oil and gas** company YPF has approved a $13.4bn takeover bid by Repsol of Spain.*

In Brief

Russia imposes new oil export tax

The Russian government plans to impose a new export tax of $1.35/t on domestic oil companies, according to a recent edition of the United Financial Group's *Russia Morning Comment.*

The aim of the tax – which requires formal approval – is to finance the $500mn construction of a new oil pipeline from northern Russia to the Gulf of Finland. At present, it is not clear which fields the Baltic Pipeline System (BPS) will serve, although it is thought that its ultimate capacity will be in the region of 30mn tonnes. Russian exports currently total around 100mn t/y.

Despite the imposition of the new tariff, exporting will remain a more attractive option for companies than selling in the domestic market, states the UFG. The following table outlines the position before and after the imposition of the new tax, using current export prices, and contrasts this with the domestic sales position.

Prices	Export ($/b) Existing	Export ($/b) From 1 May	Domestic ($/b)
Export price	**13.75**	**13.75**	
Export duty	(0.73)	(0.73)	
Pipeline tariff and port expenses	(2.74)	(2.74)	
Additional tariff for BPS		(0.19)	
Wellhead price	**10.28**	**10.10**	**4.47**
VAT @ 20%	–	–	(0.75)
Excise Rb55	(0.30)	(0.30)	(0.30)
Royalty @ 8%	(0.80)	(0.78)	(0.27)
MRT @ 5%	(0.50)	(0.49)	(0.17)
Road tax @ 2.5%	(0.25)	(0.25)	(0.09)
Housing tax @ 1.5%	(0.15)	(0.15)	(0.05)
Net price	**8.29**	**8.12**	**2.84**

Source: Russia Morning Comment

Position before and after new export tax, compared with domestic sales position

Going greener with Gree*nergy* LPG

Gree*nergy* has unveiled a new addition to its portfolio of 'greener' fuels – Gree*nergy* LPG. Compared with 'conventional fuels', LPG offers low emissions of particulates, carbon monoxide, sulfur and oxides of nitrogen – especially from starting a vehicle or running it under a stop–start cycle, says the company. LPG engines are also claimed to be quieter and more smooth running than those using diesel.

Gree*nergy* LPG is also claimed to address a 'critical environment issue'. 'Current suppliers often claim that LPG reduces emissions of carbon dioxide, the greenhouse gas, when compared with petrol or diesel,' it says. 'While this is sometimes true, this will only ever be when measured at the exhaust pipe. Our analysis shows a more accurate picture because it compares fuels on a whole-life basis, including its manufacture and distribution, and the fact that gaseous fuels are often less efficient than petrol or diesel. The actual effect is that LPG actually increases emissions of carbon dioxide compared with petrol or diesel.'

To address this issue, the company has developed an innovative programme with environmental task force Future Forests under which Gree*nergy* will plant sufficient trees to offset the carbon dioxide produced in its entirety.

At current fuel prices, this will amount to about 1 p/l. For every 400 litres of Gree*nergy* LPG sold, one tree will be planted in dedicated sites across the UK which are held in trust for a minimum of 100 years.

In addition, Gree*nergy* states that it will price its LPG below typical industry bulk prices with price transparency to allow buyers to evaluate the true costs.

Based on market prices at 13 April 1999, Gree*nergy* LPG costs 19.55 p/l (excl. VAT) compared with a typical industry bulk price of between 22 p/l and 25 p/l (excl. VAT). This equates to a cost saving of up to 21%.

United Kingdom

A report by the UK National Audit *Office on the deregulation of the UK domestic gas market indicates that consumers are saving £1bnly from tough competition and regulation.*

A 70% interest in the International *Petroleum Exchange has been put out to tender following the recent collapse in merger discussions with the New York Mercantile Exchange. The stake has been valued at £25mn.*

Traffic on the UK roads in 1998 was *1.5% higher than in 1997 according to the latest figures published by the Department of the Environment, Transport and the Regions.*

Jet has launched a 'hassle-free' LPG *service to all potential fleet operator customers. The free service comprises: technical support, site surveys, inspections, training, insurance cover, maintenance and demonstrations as well as freephone enquiries and ordering (0800 163148).*

Halifax is understood to be planning to *install 200 cash machines at Esso service stations in the UK in a bid to increase its presence outside the high street.*

Kuwait Petroleum (Q8) reports that it *has invested over £250,000 on an unmanned petrol station (automat) at the Oxford, Swindon & Gloucester Co-Op's Caterton, Oxfordshire, supermarket site.*

Europe

A joint venture led by Greece's state *owned oil refining group Hellenic Petroleum is reported to be paying $32mn for a majority interest in Macedonia's Okta oil refinery.*

Rosneft and Slavneft owned Yukos *Petroleum Bulgaria has won the privatisation tender for Petrol AD, the largest Bulgarian network of service stations.*

German passenger transport company *for the city of Saarbrucken, Saartal Lines, has opened what is claimed to be Europe's largest natural gas service station. Saartal Lines operates the largest natural gas bus fleet in Germany and plans to run half of its 140-strong fleet on gas this year. The rest of the vehicles are to be converted to run on the fuel by 2004.*

Safety conscious tanker design unveiled

Shell UK has unveiled a new 'concept' road tanker for distributor operations. The 26-tonne prototype vehicle incorporates a number of safety features that are designed to eliminate or minimise health and safety risks, such as blind spots and product spillages, and increase the cost-effectiveness and speed of each delivery, says the company. Safety features include front and rear sonar sensors, CCTV, a swivelling and rising hose boom, electronic dipsticks and a tanker top fall arrest system. The tanker is also equipped with what is claimed to be the first Trading Standards-approved dry line with hose end nozzle shut-off facility.

The tanker has been developed by Shell UK, Shell Direct, Lakeland Tankers, Renault (UK) and Alfons Haar (UK), with equipment contributions from Benfell's and BH Sala, for the commercial distributor market. Lakeland Tankers built the vehicle at its workshop at Redditch.

The new vehicle is to be used at Shell Direct depots around the UK and an evaluation programme will gather feedback from drivers.

European VAT ruling set to hit sales promotions

A ruling delivered by the European Court of Justice at the end of April on oil company Kuwait Petroleum, which operates 400 UK forecourts under the Q8 banner, is set to change the face of collector promotions in the UK. The landmark judgement may force companies to pay VAT on redemption goods costing over £10 received by consumers in trading stamp schemes by classifying them as free gifts. The judgement of the Court is likely to impact many collector promotion schemes used not only by oil company and supermarket-run fuel retail outlets but also the general retail sector. The case has been referred back to the UK VAT Tribunal for a final ruling.

The case involved Q8's Sails promotion which ran at over 300 of its sites from 1991 to 1996 in which customers were entitled to one stamp (Q8 Sail) for every 12 litres of gasoline purchased. These could be redeemed against goods in a catalogue, ranging from cutlery to televisions and video recorders.

Customs & Excise saw these goods as free gifts and sought to charge the company VAT on all redemption items claimed which cost over £10. Ironically, this is reported to be in direct conflict with its own new interpretation of such schemes announced in June 1996 in *Business Brief 10/96*. The Brief stated that the items redeemed in such promotions were not free gifts as their cost had been included in the price of the premium goods (in this case the fuel), on which VAT had already been paid. No further tax was therefore due.

Steve Boocock, Marketing Manager for Q8 said: 'We are very disappointed with the European Court's ruling. This decision contradicts Customs & Excise's own interpretation of the VAT Rule on Business Promotion Coupon Scheme Gifts made in its *Business Briefing 10/96* back in June 1996. This may presumably now have to be withdrawn.

'Customers recognise that the price they pay at the pump has to cover more than the petrol alone and that these gifts are not free but, like other operational and marketing costs, are included in the price of what they buy.

'Collector schemes are extremely popular with consumers and have been an integral part of many products and brands for years. This ruling will have major ramifications and will mean many successful schemes with large followings may no longer be affordable and will have to be discontinued. Ultimately, neither the consumer, the Treasury, or business will benefit.'

Thrust has Flare for franchising

Many of the members of Flare, the organisation for independently branded suppliers of fuel in the UK, have agreed to become Bayford Thrust franchise distributors. Flare has had its own retail brand for a number of years, with over 100 sites across the country supplied by the members. However, the members felt it lacked the sharp retail imaging and marketing support needed in today's fiercely competitive market, explains Thrust.

Bayford Thrust recently secured Conoco/Jet as a franchise distributor (see *Petroleum Review*, March 1999) in a deal which it says added 'great credibility to the Thrust brand and the retail marketing package offered'. However, for logistical reasons, Conoco does not have distributors covering the whole of the UK and Ireland and Flare members are reported to have 'plugged a useful gap'.

Flare members that have become Thrust franchise distributors include: GB Lubricants and Fuels, Southern Counties and Kent and Sussex Fuels, Barton Petroleum, and Evesons Fuels.

The New York Mercantile Exchange *(Nymex) and Deutsche Borse are understood to be planning to launch Germany's first energy exchange by the end of the year. It is reported that the exchange will initially offer futures based on the country's electricity market, which is currently being liberalised under an EU directive.*

North America

Arco has announced plans to test a *smart card payment system at a number of its service stations in southern California and Arizona later this year. Such payment systems have proved popular in Europe but have been relatively slow to take off in the US, says the company.*

Chevron is to sell all its shares in *Plantation Pipe Line Company to Kinder Morgan Energy Partners for $124mn. Plantation is a major transporter of petroleum products from refineries in the US Gulf Coast to markets throughout the southeastern states.*

Chevron is to sell its West Texas gath- *ering pipeline system to Plains All American Pipeline for $40mn. Assets include 400 miles of pipeline, gathering lines, pump stations and trunk lines used in transporting 98,000 b/d of oil produced throughout the Permian Basin to Midland, Texas.*

Middle East

The government of Saudi Arabia is *reported to have increased gasoline prices by 50% to 0.90 riyal per litre (15p/l) as part of a revenue raising programme.*

Russia & Central Asia

The Russian government is planning to *impose a tax on service stations instead of the previously announced increase in gasoline duty, reports the United Financial Group's* Russia Morning Comment. *The fixed monthly charge of Rb7,000–10,000 ($300–$400) per station is expected to shift the tax burden to small retailers. Major oil companies would be the least affected by the tax.*

BP Amoco has announced that it plans *to build 15 new service stations in Russia this year, according to the United Financial Group's* Russia Morning Comment. *The company currently operates 10 sites in the country.*

April UK fuel prices

	Pence per litre
Diesel	
Lowest: Southend-on-Sea	70.38
Highest: Oban	74.42
National average	72.81
Unleaded gasoline	
Lowest: Southend on-Sea	68.89
Highest: Oban	71.64
National average	69.90
Four-star gasoline	
Lowest: Southend on-Sea	74.15
Highest: Inverness	79.14
National average	77.16

Source: *PHH Allstar Fuel Report*

California fuel cell group

Shell has joined the 'California fuel cell partnership' – a collaboration between the state of California, energy companies and vehicle manufacturers which will test fuel cell-powered vehicles under real, day-to-day driving conditions. Shell states that it 'can make a major contribution' to the partnership through the use of its proprietary Catalytic Partial Oxidisation technology which is said to have already been shown to be able to convert liquid fuels into a hydrogen rich gas.

The partnership plans to put about 50 fuel cell vehicles on Californian roads between 2000 and 2003. As well as testing these vehicles, the partnership will also address fuel infrastructure issues and evaluate technology for using gasoline as a source of hydrogen to power the vehicles.

Atlantic LNG expansion targets Spanish market

The first cargo of LNG from the Atlantic LNG Company of Trinidad and Tobago was loaded on 19 April and celebrations were still in progress when the country's Energy Minister, Finbar Gangar, announced that negotiations would soon begin to expand the company's \$950mn LNG plant by the addition of two more trains, writes *David Renwick*.

Discussions are due to conclude by the end of this month. If successful, as expected, Atlantic will increase its present single train capability of 3mn t/y of LNG to 9mn t/y and boost gas plant intake from 450mn cf/d to 1.35bn cf/d.

Atlantic's shareholders – Amoco Trinidad (LNG) (34%), British Gas Trinidad LNG (26%), Repsol LNG Port of Spain (20%), Cabot Trinidad LNG (10%), and National Gas Company Trinidad and Tobago LNG (10%) – are keen to strike while the market is hot and to beat Nigeria, Algeria and others at their own game.

The output of Atlantic's first train has long been pre-sold to Cabot of Boston (60%) and Enagas of Spain (40%) for a 20-year period. Markets have already been identified for trains two and three. Enagas, a subsidiary of Atlantic shareholder Repsol, triggered the urgency to add two more trains by offering last year to buy between 60% and 65% more LNG from Atlantic.

Spain's gas market is currently 'exploding' because of industrial and power development. Atlantic intends to seize the opportunities in both the 'conventional' Spanish gas market, where prices are linked to oil, and the Spanish power market, where prices are influenced by electricity pool prices. The remaining 30% to 40% of gas resulting from the expansion that Repsol/Enagas is not buying is likely to be sold in the US, either to Cabot or to other importers on the eastern seaboard.

Asia-Pacific

UK-based Foster Wheeler has secured *a detailed engineering design contract from Shell for the Malampaya field gas plant in the Philippines.*

Conoco and joint venture partner Sime *Darby are understood to be planning to construct 100 service stations in Malaysia over the next four years.*

Shell is reported to have unveiled *plans to open and directly operate around 20 new service stations in Thailand after some 100 of its 850 dealer-run sites close this year.*

The Petroleum Authority of Thailand *(PTT) is reported to be planning to close around 300 (20%) of its Thai service stations in a bid to improve competitiveness.*

Latin America

Repsol has indicated that it is prepared *to sell a refinery and some 800 service stations in order to allay concerns about its potential dominance of the Argentinian energy market if its proposed merger with YPF is successful. The Spanish oil and gas company already owns 66% of Argentinian oil and gas producer Astra Capsa which, in turn, owns 93% of the Eg3 service station network.*

Africa

Electricite de France is reported to have *agreed a \$760mn deal to build two 650 MW, gas-fuelled power stations at opposite ends of the Suez Canal in the Gulf of Suez and Port Said, Egypt.*

UK Deliveries into Consumption (tonnes)

Products	†Mar 1998	*Mar 1999	†Jan–Mar 1998	*Jan–Mar 1999	% Change
Naphtha/LDF	279,491	307,602	775,418	875,304	13
ATF – Kerosene	677,354	709,713	1,935,904	2,046,107	6
Petrol	1,931,441	1,857,318	5,361,669	5,190,948	–3
of which unleaded	1,472,493	1,555,803	4,067,153	4,312,282	6
of which Super unleaded	41,306	31,148	109,167	85,424	–22
Premium unleaded	1,431,187	1,524,655	3,957,986	4,226,858	7
Burning Oil	374,214	439,410	1,083,527	1,265,552	17
Automotive Diesel	1,423,496	1,375,259	3,839,364	3,799,971	–1
Gas/Diesel Oil	677,366	664,427	1,934,619	1, 829,085	–5
Fuel Oil	235,973	267,790	844,638	641,959	–24
Lubricating Oil	72,051	66,304	214,129	189,632	–11
Other Products	689,772	742,666	2,058,450	2,240,985	9
Total above	6,361,158	6,430,489	18,047,718	18,079,543	1
Refinery Consumption	541,105	511,435	1,570,669	1,637,565	0
Total all products	6,902,263	6,941,924	19,618,387	19,717,108	4

† Revised with adjustments *preliminary

The urge to merge – where next?

Does the growing shortage of potential partners mean that we have now seen the peak of the current merger boom – or will the industry's urge to merge take it in a different direction? *Chris Chew* reports.

Perhaps the most noticeable feature of 1998's merger mania was that it was almost entirely focused on the giants. According to the *Petroleum Intelligence Weekly* (PIW)/ *John S Herold Annual Survey of Oil Market Deals*, while the total value of upstream and reserve deals ballooned to $122bn, if mega-mergers are excluded the value of upstream deals among the smaller companies actually contracted by 40% (to $22bn) compared to 1997 (see **Table 1**).

1999 has so far seen few signs of slowdown in the urge to merge. BP continues to lead the field with a somewhat opportunistic bid for Arco, but Repsol, Lasmo, and Norsk Hydro have also entered the fray (see **Table 2**). But, while almost every company in the industry is now 'in play' – either as a predator, the prey, or both – there may now be signs that the shape of the merger boom may be changing.

Until recently, the main force driving mergers was the desire to become as big as possible as quickly as possible, and the liquidity-fuelled stock markets in the US and Europe continue to make all-paper transactions relatively easy and painless. However, as Fred Lucas of Cazenove notes, the big integrated companies are reaching the point where the cultural and associated merger integration risks inherent in cross-border mergers, are becoming perhaps too large relative to the benefits of a merger. Releasing significant cost savings – the other driving force behind many mergers – also becomes very difficult if there is cultural incompatibility.

These and other considerations mean that the pool of natural potential partners, especially among the bigger, integrated companies, is rapidly shrinking as evidenced by the rather weak logic supporting the rumoured Chevron–Texaco tie-up.

But the temptation for companies to use their highly valued paper while the stock market boom continues is strong, and the shortage of large partners will mean that predators have to look elsewhere – and where better than the smaller but asset-rich E&P companies?

Elf and ENI, for example, will probably find it much easier to improve their market position by buying an upstream company than by finding a culturally compatible integrated company as partner. The UK upstream sector is a relatively cheap source of globally dispersed assets, and it has also found itself with a positional problem. Tony Craven-Walker, Chairman of Monument, recently contrasted the dismal long-term return on investment of the UK upstream sector of some 4%/y with its capital cost of over 15%. He also drew attention to the difficulty faced by medium-sized E&P companies in managing assets efficiently once they had been discovered. Many of these companies are caught in a size trap: too big to be pure explorers, but too small to exploit discoveries efficiently.

The sector clearly cannot survive in its present form, and the abolition of the sector's separate identity in the FTSE indices in April perhaps symbolises the lack of a future. The recent oil price slump, however, has resulted not only in a heightened sense of realism within the sector, but also a desire to move quickly while market conditions are favourable. This combination of willing buyers and willing sellers, backed by much stronger industrial logic than can currently be found among the integrated companies, provides a strong indicator as to where the urge to merge is now taking the industry – upstream.

The oil sector had another excellent month in the stock market, thanks to continued strength in the oil price and a steady stream of merger announcements – and rumours. The demise of Leon Hess, Chairman of Amerada Hess, has triggered speculation that Hess's 25·4% stake in Premier may be up for sale, and there has also been a revival of speculation regarding an Amerada–Enterprise merger.

The rumour-mill churned out other possible pairings in varying degrees of plausibility: Chevron and Texaco is a hot favourite at the time of writing but Elf–Total and even Shell–Elf have been making the rounds.

Back on more solid ground, the real deals announced included Norsk Hydro's bid for Saga and Lasmo for Monument. The Lasmo deal is an agreed bid, although the premium is such that an alternative bid would in any case be unlikely. The Saga end-game may be less clear cut. The Norwegian oil industry has only recently admitted to itself that some kind of rationalisation is necessary and the bid from Norsk Hydro may not be the end of the story. Statoil has indicated that it may want to bid, and even non-Norwegians may be tempted to bid for Saga as a way of expanding their North Sea asset base.

BP–Amoco	$36.6bn	Merger
Exxon–Mobil	$56.4bn	Merger
Arco–Union Texas	$2.8bn	Asset acquisition
British Borneo–Hardy Oil & Gas	$0.5bn	Merger
Global total		**Implied $/boe**
1998	$122.1bn	$7.35
1997	$37.6bn	$4.31
1996	$11.9bn	$4.45
1995	$8.6bn	$4.37

Source: PIW/John S Herold

Table 1: Upstream and reserve deals in 1998

Bidder	Target	Terms	Value	Comment
Lasmo	Monument	3 Lasmo for 7 Monument shares	$0.8bn	Complementary asset fit, but high premium paid.
Norsk Hydro	Saga	1 NH for 3 Saga shares	$2.8bn	Politics much in evidence. Saga may look for another suitor.
Repsol	YPF	$44.78/share for balance not already owned	$13.4bn	Purchase of balance after buying 14.99% stake from government.
BP	Arco	0.82 BP ADR for 1 Arco share	$26.8bn	Agreed bid, 26% premium to pre-bid market capitalisation.

Source: Press reports, company announcements

Table 2: More merger mania in 1999

Are the Middle East oil giants opening up?

Looking at the Middle East, one is always impressed by the size of the region's oil reserves and also by the contrast between its share of world reserves and its share of world production, writes *Manouchehr Takin* of the Centre for Global Energy Studies (CGES).* Although the region holds 65% of world reserves of crude oil, its share of production is less than 32%. The following analysis of the Middle East oil sector summarises the current state of play and offers an insight into future trends.

The relationship between reserves and production within the Middle East itself also varies between different countries. As shown in **Table 1**, for countries in group (a) the share of production is less than the share of reserves. On the other hand, for those in group (b) the share of production is greater than the share of reserves.

The difference between reserves and production positions is striking and a number of factors contribute to this. The technical characteristic of the fields is one factor, but the difference is mostly attributable to the oil policies of the countries. Observing Opec quotas obviously imposes a limit on the production of those countries that are members of the organisation, as in group (a). However, Qatar, a member of Opec, is in group (b) with a higher production share because of its upstream investment policy. Allowing foreign company participation has resulted in the growth of production in Qatar. Its crude oil production has increased from less than 400,000 b/d in 1991 to nearly 700,000 b/d today – an impressive result from the opening of its oil sector.

A similar situation exists in the Neutral Zone. The Zone's production and reserves are included in Kuwait and Saudi Arabian data in the table. However, if taken separately, the Neutral Zone would also be in group (b). This is a policy choice for the countries themselves. As sovereign states they may choose a slow or a rapid depletion policy and no policy is recommended here. However, for a fast growth in production, the private sector has had a more successful track record.

Investment and technology

The need for heavy investment in the upstream sector of the Middle East was emphasised by the CGES several years ago.[1] Funding is needed for increasing the production capacities as well as maintaining the existing capacities. It was noted that within the system of national industries in these countries, the oil sector has been competing for scarce capital with the other sectors of the domestic economy such as health, education and defence. Over the years and with the priority given to investment in the other sectors, the oil sector has suffered, although the extent of this under-investment differs among the countries of the Middle East. Nevertheless, over the last decades this situation has resulted in the deterioration of the reservoirs. The problem is more acute in the ageing fields of the region. The remedy involves much greater expenditure than would have been necessary if under-investment had not occurred in the first place.

These issues were further elaborated in a series of CGES field-by-field studies on four countries between 1992 and 1997.[2] The studies constitute reference handbooks and are, we believe, still the best systematic sources of information on the oil and gas fields of Iran, Iraq, Saudi Arabia and the United Arab Emirates, with data on reserves, production history, reservoir characteristics, field development activities, future potential and, in the case of Iraq, also an evaluation of the country's exploration potential and prospectivity. These detailed studies confirmed the earlier CGES emphasis on the requirements for heavy investment and the application of new technology.

On the other hand, under the present economic conditions in the region, the capital cannot easily be provided domestically. These countries are no longer rich in 'petrodollars' as they were in the 1970s. The continuing decline in the price of oil since the early 1980s has eroded their surplus revenues and foreign reserves. In addition, the eight-year Iran/Iraq war, the Iraqi occupation of Kuwait and the Persian Gulf War resulted in serious damage or almost complete destruction of the infrastructure and the hydrocarbon sectors of Iran, Iraq and Kuwait. The wars and the subsequent reconstruction efforts have drained the financial resources of Iran, Iraq and Kuwait. The resources of other countries have also been depleted through the Desert Storm operations and the ensuing Western military presence in the Persian Gulf.

Furthermore, the generous social welfare system established during the period of high oil prices imposes a heavy burden on government budgets in all these countries. A rapidly increasing population, a growing number of young people and the need for education and employment have exacerbated the situation. Any reduction of subsidies

Country	Reserves (%)	Production (%)
Total Middle East of which:	65.1	31.7
(a) Iran	8.7	5.4
Iraq	10.9	3.2
Kuwait	9.3	3.1
Saudi Arabia	25.3	12.6
United Arab Emirates	9.5	3.4
(b) Oman	0.5	1.3
Qatar	0.4	1.0
Syria	0.2	0.8
Yemen	0.4	0.6

Source: Oil and Gas Journal *and the CGES*

Table 1: Percentage shares of total world crude oil reserves and production, 1998

and public services could cause serious social unrest. Under these conditions, the oil sector faces an even tougher competition for securing sufficient investments for its own needs.

Middle East potential

It need not be emphasised that the Middle East contains huge oil reserves and in spite of the large capital requirements, still has the lowest cost of production in the world. The low production and high reserves position is also an indicator of the region's potential for much higher rates of oil production. The ageing fields still hold several hundred million, or even billions, of barrels of remaining oil reserves but are in need of new technology and investment. There also exist many undeveloped fields which have not been brought onstream due to their relatively complicated reservoir properties, greater depth, unfavourable location, size, etc. Needless to say, modern techniques could be used for profitably developing these fields.

The Middle East's undiscovered resource base is also huge, with much greater likelihood for discovering new reserves than in other parts of the world. New exploration work using modern techniques will result in many surprises.

Openings so far

The potential, however, has not been open to the international oil industry, except in the small producing countries of the region. The latter have long been open to foreign investment and as shown in group (b) of **Table 1,** their oil production is proportionately higher than their reserves. However, the actual volumes of oil production have remained low due to the limitation of their geological potential and their resource base. Of the countries in group (a), foreign companies have been operating in the United Arab Emirates, but due to government policy new openings have not been forthcoming or have not been in the most prospective areas.

However, the remaining four oil giants in group (a) had remained closed to foreign investment. It is the actual or potential opening of these countries that has focused the attention of the global oil industry and could have a major impact on the world oil scene. The abovementioned requirements for capital and new technology and the serious domestic economic conditions have led to major oil policy changes in these countries. The developments are interesting, particularly considering the nationalisation of the oil industry in the region decades ago. However, it should be noted that the new openings are not a return to the old concession systems. They reflect the realities of today's conditions and are business transactions similar to other activities in international trade. The conditions and the details of the openings vary in different countries.

Iran

The Islamic Republic opened its upstream sector in this decade. Following a few years of negotiations, the country's national oil company (NIOC) and US company Conoco reached an agreement to develop Iran's offshore Sirri A & E fields in March 1995. This agreement, however, was cancelled by a US presidential executive order and American companies were barred from Iran. The French company TOTAL later finalised the deal on these fields. Since then many other upstream projects have been announced for foreign company participation.

In spite of the threat of secondary sanctions to be imposed by the US on non-US companies investing in Iran, interest has been keen even though progress has been slow. Some projects have already been allocated to foreign companies and other projects are in an advanced stage of negotiations. It is interesting that the projects include exploration as well as field development and production improvement in both onshore and offshore areas.

These agreements have been under the so-called 'buy-back' model, where the foreign company provides the investment and carries out the development project and transfers the field's operation to NIOC. The expenditure incurred by the company together with bank charges and an agreed remuneration are paid back through oil resulting from the project. It is interesting that the company bears no risk for any variation in the price of oil since this is taken into account in the payments. The company, however, is responsible for completing the project on time and within an agreed expenditure limit.

Iraq

The CGES study confirmed Iraq's proved oil reserves of more than 110bn barrels and its huge potential of more than 200bn barrels. Iraq has announced many development projects for giant and super-giant fields and also a number of blocks for exploration in Iraq's Western Desert. Offering production sharing agreements, Iraq has conducted negotiations with many foreign companies for these projects and agreements have been reached with some companies.

The agreements, however, are pending the lifting of UN sanctions which are still in place nine years after Iraq occupied Kuwait. The prize is so attractive that the international companies keep an active interest and continue their presence in Iraq, to be ready when the sanctions are finally lifted.

Kuwait

In Kuwait, foreign companies became active in the upstream sector soon after the liberation of the country from Iraqi occupation. The companies' activities were under technical service agreements. They worked on different projects, such as the evaluation of reservoir damage in the Burgan field caused by the blow-out and fires during the Iraqi occupation.

A greater involvement of foreign companies has since been debated within Kuwait and is now approaching the final stages of decision making. Proposals have been drafted in the form of operating service agreements under which foreign companies could work in some of the northern and western parts of the country. The fields in the north have a greater priority. These proposals have to be presented and approved by the Supreme Petroleum Council and the National Assembly (the Parliament). The requirements are for the application of enhanced oil recovery, water injection and other activities for production improvement. For the five fields in the north, their production is to increase from 400,000 b/d to 900,000 b/d by 2005 and the production in two fields in the west is to increase from 190,000 b/d to 460,000 b/d. The total remaining reserves are a staggering 16bn barrels.

These developments are part of the plans for Kuwait to reach a sustainable production capacity of over 3mn b/d by 2005.

Saudi Arabia

The biggest prize in the Middle East, however, is Saudi Arabia. A great deal of excitement was aroused in autumn 1998 when the country's Crown Prince while on a visit to the US, invited some major American companies to give proposals for Saudi Arabia's oil and gas industry. Many chief executives have since visited Saudi Arabia and have had meetings with the Crown Prince and oil industry officials. Details of the proposals and the discussions are not publicly available.

There are conflicting signals for the upstream opportunities. The policy differences between Aramco and government authorities also have to be clarified. Some statements suggested the prospects will be more for the downstream sector. Foreign companies have long been involved in refining activity and this could be expanded. The new emphasis appeared to be on the processing and transportation of gas and possibly electricity generation. With Saudi Arabia holding about 2.5mn b/d spare oil production capacity, no sense of urgency was anticipated for upstream activities relating to oil, and gas exploration and production was said to be carried out by Aramco. However, more recent statements indicate that Saudi Arabia will be opening its fields to private companies.

Furthermore, the extent of downstream involvement is not that clear. In particular, the produced gas and electricity have to be delivered to government or domestic industries. This is an important issue for foreign investors, especially in the face of government price control and a history of late payment or even non-payment by customers.

The future

The prospect for the opening of Middle East's upstream sector is very exciting. Some enthusiasts see this as the beginning of a major geographical shift, whereby the global oil industry will move its investments and its operations to the Middle East.

However, the initiation of these openings will be a slow process due to both endogenous and exogenous factors. As noted above, in Kuwait and Saudi Arabia internal debate and decision-making processes have continued for some years. In Iraq the UN sanctions have effectively halted the opening, but in Iran the US sanctions have been less effective. Nevertheless, the four 'giants' in the region are already on the path leading to the entry of international companies in their oil and gas sector. ●

1. For example, see 'The Cost of Additional Oil Production Capacity in the Gulf,' *Global Oil Report*, Jan–Feb 1991, p25–32.
2. *Oil Production Capacity in the Middle East, Volume I: The United Arab Emirate*, CGES, 1992, 178 pages.

   Oil Production Capacity in the Middle East, Volume II: Saudi Arabia, CGES, 1993, 258 pages.

   Oil Production Capacity in the Middle East, Volume III: The Islamic Republic of Iran, CGES, 1995, Book 1 – 210 pages, Book 2 – 293 pages.

   Oil Production Capacity in the Middle East, Volume IV: Iraq, CGES, 1997, Book 1 – 191 pages, Book 2 – 335 pages, Book 3 – 260 pages, Book 4 – 280 pages, Book 5 – 173 pages.

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extended periods when production was well below installed capacity. Over recent years spare production capacity has been very largely confined to the Opec Middle East states.

In order to get a more realistic assessment of the trends in Opec well productivities, three periods when it is known they were operating close to capacity are appropriate. In both the 1973/74 and 1979/80 oil crises Opec capacity was being operated virtually flat out. Individual countries peaked at slightly different dates in the two periods. In February 1998 most Opec members were also at or close to capacity. The only real exception being Saudi Arabia whose installed capacity is usually estimated at 10.2mn b/d.

Of the main Opec oil producers all but Algeria had their highest outputs in the 1970s. Algeria's oil output has declined over the period but been more than offset by its gas liquids production. Venezuela reattained its 1973 level in 1997 but has not yet surpassed its 1970 level. With the sole exception of the low well productivity Venezuela all Opec members have experienced declining well productivities with levels now one-third to one-half of their 1973/74 levels. A great deal of investment and many new fields will be needed to reverse the well productivity decline. Lower cost field development technology is urgently needed if the industry's profitability and ability to shoulder a heavy tax burden is to be maintained. ●

Country	1973/74	1978/79	Feb 1998	Peak production	Year
Algeria	1,200	1,100	682	1,440,000	1997
Indonesia	499	535	162	1,685,000	1977
Iran	15,600	9,361	3,324	6,021,000	1974
Iraq	15,300	15,266	1,469	3,475,000	1979
Kuwait	4,300	4,064	2,791	3,000,000	1972
Libya	2,500	1,800	777	3,320,700	1970
Nigeria	2,100	1,450	1,100	2,300,500	1979
Saudi Arabia	12,050	13,100	6,241	9,999,000	1980
Abu Dhabi	8,000	5,600	1,985	1,633,000	1977
Venezuela	265	190	229	3,760,000	1970

Source: World Oil, Oil & Gas Journal, BP Statistical Review of World Energy, *analysis by* Petroleum Review

Table 3: Opec well productivities and maximum production levels in barrels per day

Cracking the heavy oil problem

Upgrading heavy oil usually involves building massive facilities costing in excess of $1bn. Now, a pioneering engineer may provide a cheap, flexible alternative, reports *Gordon Cope*.

Sometime this autumn, construction will begin on Gulf Canada Resource's new upgrader in the heavy oil district of Alberta, based upon a revolutionary design by Ensyn Group, an Ottawa-based technology firm. 'We are hopeful that our relationship with Ensyn will help unlock the potential of Gulf's significant heavy oil and oil sand assets,' said Gulf President Richard Auchinleck.

What makes the upgrader revolutionary is not that it is large – several multi-billion-dollar projects for 100,000 b/d-plus upgraders have recently been announced – but that it is small. 'The optimum size for our reactors may be in the 2,000 b/d range,' says Dee Parkinson-Marcoux, President of Ensyn Energy Group, of Calgary. 'We estimate it will cost C$10,000 per daily barrel production, or less. Capital costs per barrel will be in the C$1/b to C$1.50/b range (when amortised over 20 years), and operating costs are estimated to be in the C$1.50/b range.'

Being able to build an economically-viable mini-upgrader for a mere C$20mn has staggering implications for the heavy oil industry. Heavy oil is highly viscous petroleum, usually under 20° API. Production often requires closely spaced wells and enhanced oil recovery techniques, such as steam injection.

The Canadian Association of Petroleum Producers (CAPP) estimates that the oil sands and heavy oil region in Alberta contain 300bn barrels of recoverable oil, out of total reserves of 2.5tn barrels. Production of in-situ heavy oil, mostly centred around Cold Lake, Alberta, hovers around 500,000 b/d, approximately one-quarter of Canada's total daily oil production.

Unfortunately, heavy oil is not as suitable as conventional oil for making refined products. It is so thick and tar-like that it is not easily transported by pipeline and it is often mixed with expensive condensate in order to reduce its viscosity. Once at the refinery, it cannot readily be 'cracked' using conventional refinery units but has to be refined in a coker.

A coker employs severe thermal cracking. The heavy oil feedstock is heated to 475°C to 520°C in a furnace for about 60 seconds, then discharged into the bottom of a large vessel called a coke drum. Lighter hydrocarbons rise to the top of the drum and are drawn off for further refining. The remaining product, primarily solid carbon, is known as coke.

Cokers are expensive to build and operate. Husky Oil's 40,000 b/d upgrader in Lloydminster, Alberta, cost C$1.6bn to build. All but the largest companies are restricted from building upgraders by the prohibitive costs.

Parkinson-Marcoux was well aware of the problem. She worked for Esso as a refinery engineer and for PetroCanada running refineries. As an Executive Vice President of oilsands producer Suncor, she oversaw the conversion of the antiquated bucketwheel and conveyor system to a more efficient shovel and truck system, lowering production costs from C$18 to C$13/b.

In 1996, Parkinson-Marcoux signed on as President of CS Resources, a Calgary-based heavy oil company. 'Eighty-nine per cent of their 14,000 b/d was heavy, so, unless they found somebody to upgrade their oil for them, which is difficult, they needed a small facility.' Parkinson-Marcoux was charged with the task of finding an efficient, economical upgrader to suit the company's needs.

Unfortunately, CS Resources was sold the following year, and Parkinson-Marcoux left the company. She retained her interest in finding an efficient technology for a mini-upgrader, however, and, in 1997, when she heard about Ensyn Group Inc, a corporation with a process that made liquid fuel out of wood, she went for a tour of its pilot facility near Ottawa, Canada.

The process proved to be a success. There are currently four commercial plants operating in the US and Canada, and four more planned, including one in the UK (at Corby, in Northamptonshire), each converting wood wastes into bio-oil. 'The liquid looks like espresso, pours like diesel and smells like smoke,' explains Parkinson-Marcoux. 'It contains phenol-like compounds, the building block for many natural chemicals.'

When Parkinson-Marcoux visited the test facility near Ottawa, she immediately realised its potential to the petroleum industry. 'Biomass reactors are very similar to heavy oil reactors,' she notes. 'The biomass reactor in Ottawa could take oil or biomass as a feedstock, with minimal conversions.' She formed Ensyn Energy Group and negotiated the rights to the technology and applications in the petroleum field.

Making light of heavy chore

The process for both biomass and heavy oil is called Rapid Thermal Processing, or RTP™. The heavy oil or oil sand feedstock is injected, along with hot sand, into a reactor. The hot sand mixes with the feedstock and superheats it to between 400°C and 700°C within 200 to 500 ms. The oil is converted into a vapour and coke, with the coke clinging to the sand. The vapour is drawn off and condensed, while the sand/coke mixture is conveyed to a reheater, where the coke is burned off the sand. The hot sand is then recirculated to the reactor, where the procedure is repeated. All of this occurs at atmospheric pressure, without a catalyst.

Process yields exceeding 86% of the original feedstock have been achieved. The liquid, which is pipeline-ready, is low viscosity, low naphtha, and high in kerosene, diesel and gas/oil cuts. 'It's a very attractive feedstock for catalytic and hydro crackers.' According to Parkinson-Marcoux, not only are RTP™ upgraders inexpensive, they are also easy to construct. 'You can build one in nine to twelve months on a modular basis and ship it out to the field on a flat-bed truck.'

Before committing to a commercial application, Gulf, which has over 5bn barrels of heavy oil reserves, undertook due diligence on the process. It was so impressed with the technology that it signed a C$19mn contract that will include a 1,000 b/d module in operation in northeast Alberta by the end of 2000. 'If this technology works the way everyone is hoping, it will allow us to upgrade on site and add value,' says Gulf spokesperson Jennifer Martin.

A successful application of RTP™ technology will give the myriad of small producers in Canada a leg-up into the future. 'As conventional crude production in Canada declines, you have to replace it with heavier and heavier crude if you want to stay in the business,' says Parkinson-Marcoux. 'Big refiners are not interested in adding expensive technology, so small producers will need to upgrade themselves. Now, they will be able to.'

Australian initiatives tackle global warming

Australia is making significant progress in developing a coordinated response to climate change with many existing policies and measures already addressing greenhouse gas emissions from key industry sectors. The development of possible instruments such as emissions trading is also under active consideration, reported *Gwen Andrews*, Chief Executive of the Australian Greenhouse Office (AGO)* at a recent emissions trading conference in London.

Australia has introduced, or is putting into place, an array of measures aimed at tackling emissions associated with climate change. In November 1997, Prime Minister John Howard announced a significant package of measures to address the issue – allocating A$80mn over a five-year period. The funding package – which targeted emissions from the residential, agriculture, forestry, transport, energy and industry sectors, as well as government operations – initiated a number of new measures and substantially expanded a group of existing programmes.

This package ensured that Australia's negotiations at Kyoto in December 1997 were pursued within an environment of credible domestic programmes aimed at reducing greenhouse gas emissions. The measures include a mix of voluntary, regulatory and incentive approaches projected to reduce Australia's emissions to 118% of its 1990 emissions (excluding land use change).

Australia's commitment at Kyoto was to limit the growth of its greenhouse gas emissions to a level of only 8% above that which prevailed in 1990, over the five-year commitment period between 2008 to 2012. Under normal economic growth assumptions it is estimated that this target represents a requirement to cut emissions by about 30% from business-as-usual scenarios, a task equivalent to that facing most OECD economies.

At this stage the actual amount of emissions attributable to Australia for 1990 (the baseline) has not been determined. Methodologies for estimating emissions from activities such as land clearing are being developed through a major initiative to establish a National Carbon Accounting System (NCAS). Plans call for establishment of the baseline via the NCAS by 2002.

National Greenhouse Strategy

The Prime Minister's 1997 package set the groundwork for the development of Australia's National Greenhouse Strategy (NGS) released on 26 November 1998. The NGS has been agreed by the Commonwealth, state and territory governments, and sets down the framework within which the Commonwealth, state and territory governments will take action as part of a national effort to reduce greenhouse gas emissions.

The goals of the strategy include:

- Limiting net greenhouse gas emissions, in particular to meet Australia's international commitments.
- Fostering knowledge and understanding of greenhouse issues.
- Laying the foundations for adaptation to climate change.

The Australian government has yet to make a decision on the establishment of a national emissions trading system. However, under the auspices of the National Greenhouse Strategy, it has asked the Australian Greenhouse Office (AGO) to examine the feasibility of implementing such a trading system in Australia.

Parliamentary inquiry

A House of Representatives Standing Committee on the Environment, Recreation and the Arts (HORSCERA) conducted an inquiry into the regulatory arrangements for trading in greenhouse gas emissions and released an interim report on 27 August 1998. An analysis of the submissions to the House of Representatives Standing Committee inquiry indicates widespread support for emissions trading as the lowest cost means of meeting our Kyoto Protocol commitments – albeit with qualifications in some cases.

The HORSCERA inquiry into emissions trading attracted 74 submissions from a variety of bodies, including industry, environmental and community groups, Commonwealth government departments and state governments. It made the following recommendations in the interim report:

- Emissions permits should be licences to emit which are issued on terms that are clear, understandable and known. The licences should not confer property rights.
- There should be an early trial of emissions trading in Australia under the following conditions:
  - participation should be voluntary;
  - it should be based on emission levels at the beginning of the trial;
  - it should not prejudice the eventual design of the compulsory scheme, except for a guarantee that emission reductions achieved during the trial would be recognised in any subsequent compulsory scheme;
  - consideration should be given to a preferential treatment of participants in the trial when allocating permits in any subsequent compulsory scheme; and
  - consultation about the design of the compulsory scheme should continue.

Emissions trading system

Much of the detail on the cost and feasibility of different options for implementing and operating an emissions trading system remains to be filled in. Much more information also needs to be gathered on how various aspects of the design of a trading system will affect various sectors and industries.

A primary task for the AGO is consultation to make sure the views of all sectors are taken into account. It has therefore embarked on a strategy of engaging key experts, state and territory governments, industry, other stakeholders and the general public in this process. A series of four discussion papers that detail the options and issues that arise in moving from broad theoretical considerations of emissions trading to a widely accepted, workable and cost-effective system are to be published during 1999. These papers will be widely circulated for consultation, and advice will be developed for government during the year. The discussion papers are aimed at establishing a framework for future policy deliberations, without pre-empting policy decision.

The first paper in this series was released in March 1999. Entitled *Establishing the Boundaries*, it discusses the comprehensiveness of a national emissions trading system within Australia, focusing on the greenhouse gases and sectors of the economy that could be covered.

The remaining three papers will be published by September and will include:

- *Issuing the Permits* – issues related to the allocation of permits, including grandfathering, auctioning, and recognition of early abatement action; permit duration; and the transition toward possible emissions trading within Australia.
- *Crediting the Carbon* – the design of a national emissions trading system that allows for trading in carbon credits generated through carbon sinks.
- *Designing the Market* – issues such as permit design, measurement and monitoring emissions, reporting emissions, compliance to meet government commitment to international targets, penalties and registry of permits.

Framework principles

The AGO's first discussion paper proposes a set of principles by which a national emissions trading system might work. The principles state that any national emissions trading system should be:

- Developed and operated in the context of an overall policy strategy aimed at enabling Australia to achieve compliance with any international greenhouse undertaking, including the Kyoto Protocol, ratified by Australia.
- Implemented in the least cost way to the national economy and with the aim of maintaining international competitiveness.
- Implemented in a way that distributes the cost burden of the Kyoto Protocol, and any future greenhouse commitments, equitably and in the national interest, across the community.
- Compatible with an international emissions trading system so that trade can occur across and within national boundaries.
- Implemented at the most opportune time, and assist in managing the risks and uncertainties facing Australia associated with the need to achieve compliance with its international commitments as they continue to evolve.
- Introduced in a way that facilitates adjustment within the economy necessary to achieve compliance with the Kyoto Protocol, and that recognises the dynamic nature of economic change and investment opportunities.
- Be as comprehensive as possible, aiming to cover all greenhouse gases from all sources in all sectors and to incorporate carbon sinks, but adaptable in order to accommodate new technologies and investments, and changes in international agreements.
- Designed to minimise costs through minimising prescriptive regulation, maximising flexibility for participants and maximising private sector involvement in the operation of the system.
- Open to all legal entities.

Early action

The Australian government is increasingly being asked by those companies who are taking early abatement action, whether or not they will be disadvantaged if emissions trading is introduced.

It is important that existing policies and measures continue to contribute to a transition from current levels and patterns of activity to those consistent with fulfilling our Kyoto commitments for the period 2008 to 2012, and any future obligations. For many enterprises this transition will involve adoption of energy efficiency and process improvements beyond those likely to occur as part of their normal commercial operations. Current and prospective greenhouse measures, including the possibility of an emissions trading system should facilitate that adjustment.

The issue of credit for early greenhouse abatement action is being addressed in a study commissioned by the AGO's Emissions Trading Team. The results of this study will constitute an important consideration within the emissions trading policy advice.

Establishing the boundaries

The AGO's first paper on emissions trading discusses the range of gases, activities and emissions sources covered by Australia's greenhouse gas abatement efforts. This will have a significant bearing on the overall cost and welfare implications of complying with Kyoto Protocol. Opportunities for reducing emissions are dispersed throughout the economy, and can vary in size and cost. Similarly, some emitters have greater scope to bear these costs, or pass them on, than others.

These factors will be important in determining where permit allocation and obligations might fall in an emissions trading system. One of the most compelling reasons for pursuing comprehensive emission coverage under an emissions trading system is that it maximises the chances for low-cost abatement by spreading the abatement task across a wider range of emitters.

However, the sheer number and diversity of emission sources can make comprehensive emission coverage difficult and costly to achieve in practice. In some cases locating, monitoring and attributing emissions back to their 'owners' can pose problems that cannot be entirely resolved, or which may involve significant costs to overcome. These cases highlight the need to find a satisfactory balance between comprehensiveness within an emissions trading system and the desire to minimise overall economic costs (which will include both abatement costs and the costs of administering an emissions trading system). A range of complementary measures may be needed to address emissions from sources that do not lend themselves to coverage under an emissions trading system.

Indirect approaches to estimating emissions, and requiring emission permits to be held by participants at 'focus' points in the emission stream could provide opportunities for reducing administration costs without dramatically reducing the abatement cost benefits of direct targeting. For example, the potential advantages of an upstream approach for covering combustion related emissions (which represent around 70% of the Australian total) are widely recognised. Such an approach would involve estimating emissions based on the carbon content of fuels, and would require energy suppliers to hold and acquit emission permits in respect of the quantity of fuel they sell.

Effective ways of involving other emission activities and sources, such as agricultural, industrial and waste-related emissions in a trading system are more problematic. The physical and behavioural relationships underpinning emissions from these activities are often more complex, identification and monitoring of emissions presents greater difficulties and the links between readily observed inputs (or outputs) and the emissions produced appear to be weaker.

Another important issue in terms of the boundaries of a trading system is building in flexibility. An emissions trading system should have the capacity to respond to change by extending its coverage when circumstances make it cost effective to do so. It should also be able to recognise special cases in which standardised procedures for estimating and attributing emissions impose excessive and unnecessary costs, because of the unique circumstances of participants or the effects of technological change.

continued on p22...

Will Libya be let off the leash?

If it is, the implications for the oil markets will be considerable, and for European gas markets they will be even more significant, writes *Fred Thackeray*.

The lifting of UN sanctions on Libya in April 1999 raised the possibility of an old-time rush for oil and gas concessions after a hiatus of 17 years. Since 1982 US oil companies, US know-how and US equipment have been forbidden by US sanctions. At the time of writing – in late April – these unilateral sanctions still remain. It is a widespread expectation, however, that moves will soon be made to allow US companies to seek a share of the opportunities in Libya, where, in their absence, numerous European and other companies have established major holdings and made some big discoveries.

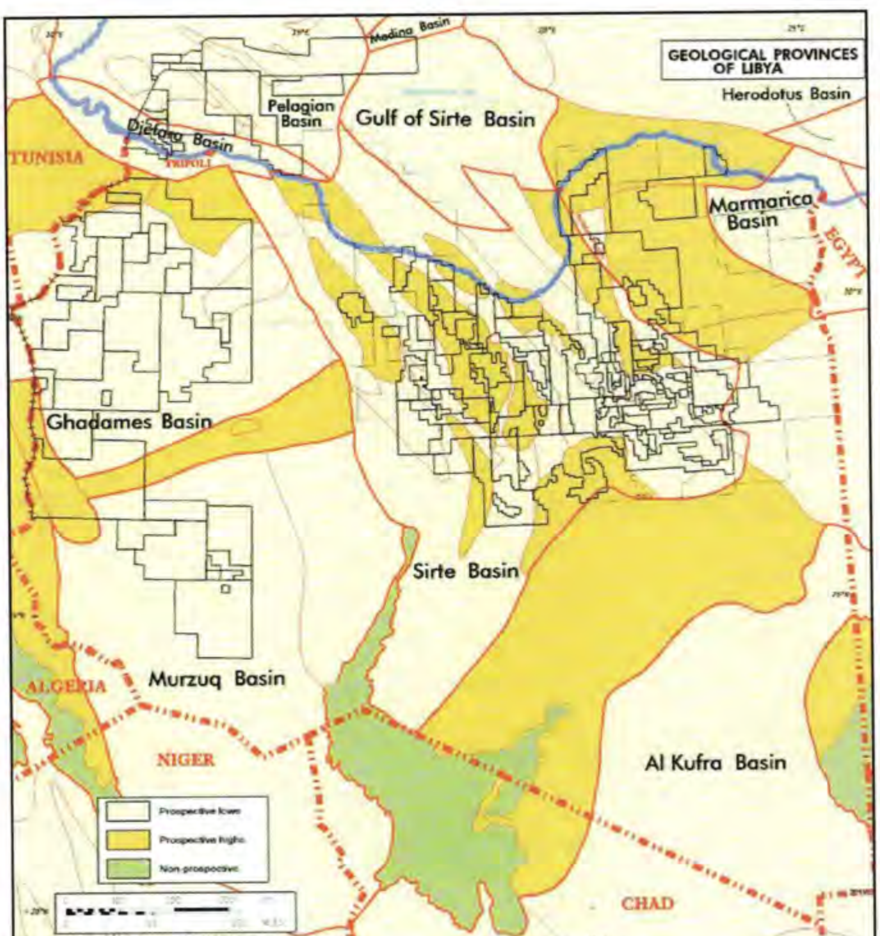
A recent conference* on Libyan developments held, fortuitously, immediately after the ending of UN sanctions, attracted a flood of over 400 participants. This demonstrated vividly the international oil companies' growing interest in low-cost areas if – as they hope – they are offered good contract terms. The Libyans were not fully prepared for the suddenness of the interest; but they sent a top-level delegation and promised publication of improved concession terms in a draft new Petroleum Law by September/October.

They indicated also that they might not necessarily wait until then to package different opportunities in discussion with interested companies. A team was established two years ago to review and rewrite the Petroleum Law, said Abdalla El-Badri, the Secretary for Energy. The new Law 'will be designed with the aspiration of developing all sectors of the oil industry in Libya, putting in service the accumulated experience of all national and international expertise in the oil industry'.

The existing terms under EPSA III (Exploration and Production Sharing Agreements III) 'are actually quite good for smaller discoveries', according to a paper presented by Jonathan Green, Senior Manager for Africa and Latin America in IHS Energy (the new parent of Petroconsultants). But, he added, 'the economics for bigger discoveries are less favourable due to the contractor's cost recovery factor'. He continued: 'It is widely felt in the industry, that Libya needs to offer better terms or better acreage.'

How far Libya has fallen behind, due largely to the sanctions, is indicated by a simple comparison of oil production in 1982 and production last year. In that period, world oil production increased by about 29%, production in Opec countries excluding Libya increased 56%, and Libya's production increased 18%. At that, it was around 1.4mn b/d. This was a far cry from its peak of close to 3.5mn b/d in 1970, when both major internationals and the so-called US independents went hell for leather to produce light sweet crudes from the quickly discovered fields in the Sirte Basin.

The scope for increasing production now, even without further discoveries, but presumably with further development expenditure, appears to be considerable. Comparisons with Libya's neighbour, Algeria, and with much-hyped Nigeria, show that Libya's proved reserves at end-1997 – according to the estimates in BP's *Statistical Review of World Energy* – were 29.5bn barrels compared with only 9.2bn in Algeria and 16.8bn in Nigeria. The Nigerians estimate a higher figure for themselves of 22bn barrels. Taking this figure and Nigerian production last year of just over 2mn b/d, indicates a rate of depletion equivalent statistically to 29 years. Applying the same depletion rate to



Basin	Sirte	Offshore	Murzuq	Ghadames	Kufra	Cyrenaica
Discovered	91	13	5	4	nil	nil
Forecast	24	12	35	11	19	6

Table 1: Libya's estimated original oil and gas in place (bn boe)

	Production in b/d Feb 1999
Libyan companies*	
AGOCO	375,000**
Waha	335,000**
Zuetina	68,700**
Sirte	47,000*
Sub-total	825,700*
Foreign companies	
Agip	152,750
Repsol	105,225
Wintershall	89,707
Veba	83,000**
TOTAL	13,500**
OMV	2,800
Fina	2,100
Sub-total	449,082**
Total all companies	**1,274,782****

Source: IHS Energy
*AGOCO (Arabian Gulf Corp) was formed in 1980 to take over BP/Hunt and Amoseas (Texaco/Chevron) concessions. Waha was formed in the mid-1980s to take over the concessions of Oasis (Conoco, Amerada, Marathon). Zuetina took over Occidental's concessions. Sirte in 1981 took Esso's holdings including its El Brega LNG plant.
** Approximate

Table 2: Companies producing oil in Libya

Libya's reserves of 29.5bn barrels would imply production of 2.8mn b/d or twice the level of about 1.4mn b/d in 1998.

Libya is cautious in its assessment of immediate prospects. According to a paper presented by Dr Najmeddin A Arifi, Chairman of Zuetina Oil Co, a short-term plan has been approved to enhance oil production capability to about 2mn b/d over a five-year period. More far-reaching, Dr Arifi remarked, is that a recent review of some major reservoirs revealed that by introducing new technology and proper investments their production could be doubled. Additionally, long-term plans are under consideration to apply new IOR (improved oil recovery) and EOR (enhanced oil recovery) techniques to further increase production capacity.

An indication of Libya's potential for future oil production was provided at the conference by Ibrahim Baggar, Exploration Manager of NOC (National Oil Corporation of Libya), in estimates of hydrocarbons originally in place totalling 220bn barrels.

The breakdown of this total by main basins in **Table 1** illustrates the emphasis on the Sirte Basin. The estimates are derived by geological modelling, using geological and geophysical information gathered over the past 40 years, except for the estimates for Kufra and Cyrenaica which are 'hypothetical'. The total figure of 220bn boe is huge. Deducting cumulative past production and today's remaining proved reserves, *Petroleum Review* arrives at an estimate that future additions to proved reserves – assuming 30% recoverability of in place reserves – would be as much as 48bn boe.

Whether this statistic is credible or not, the indication is plainly that there should be a great deal more oil and gas yet to be found and developed in Libya once the constraints of sanctions are removed.

Discovery success in the past ten years is indicated in estimates presented by IHS Energy showing 11 significant discoveries with estimated recoverable reserves of 1.8bn boe. New field wildcats drilled in the period totalled 184, with a technical success ratio of 38%. The discoveries included a major oil/gas find by Lasmo in the Murzuq Basin in 1997. Named the Elephant field, this is estimated to contain recoverable reserves of 758mn boe. It is expected to reach production of 150,000 b/d by 2002. Lasmo puts development and production costs at $5/b.

Recent information on the oil production of individual companies in Libya is shown in **Table 2**. Several of the US companies referred to in the footnote to the table have 'standstill' agreements with the Libyan government, providing some status if they seek to resume their operations in Libya.

A key feature of Libyan crude is its quality – light and low sulfur – with the principal exception of Agip's offshore Bourri field, which is 26° API. The attractions of Libyan crude quality, however, may have diminished to some extent, according to Peter Bogin of CERA, who pointed out that price differentials between light and heavy crudes may narrow as a result of major investments in European refineries to reduce the proportion of fuel oil output from heavy sour crudes.

Natural gas to take the lead

The consequences of Libya's re-emergence if US sanctions are lifted or waived will be evident first and most strongly in natural gas rather than oil markets. This will be due to the implementation of plans of the ENI group jointly with NOC. The proposal is for largescale exports of Libyan gas to Italy. In a statement about the project to shareholders in February last year, ENI's then Chairman, Guglielmo Moscati, declared that ENI does not intend to buck US sanctions, even though strictly speaking, the project may not fall legally within the sanction terms.

Nevertheless, in January this year Agip announced that it had agreed with NOC to embark on a 520-km submarine line from western Libya to Sicily to transport between 8bn to 9bn cm/y of natural gas to supply the Italian market. Known as the Western Libya Gas Development Project, the overall cost including field developments and a 500-km overland pipeline was estimated in a paper by Fuad Krekshi of Agip Gas at about $5bn.

The gas will come from two areas, the Wafa field and fields in the Agip/NOC offshore block C/NC 41 adjacent to the Bourri field. Wafa was discovered in 1991 by NOC's subsidiary Sirte Oil at a location in the Ghadames Basin some 500 km inland, southwest of the proposed export point at Zawia near Tripoli. (The Wafa field, incidentally, lies close to the Alrar field across the border in Algeria and may draw from the same reservoir.)

An overall programme of five years is envisaged from basic engineering to start-up, with first gas from the Wafa field in 2003 followed by offshore production starting in 2004.

In addition to exports of 8bn cm/y, it is intended that the Western Libya project will supply 2bn cm/y for consumption in Libya as part of a plan to further develop the local gas market. According to a paper presented jointly by Agip and Sirte, participation of international oil companies in gas distribution and marketing in Libya is 'possible' and the NOC 'will be looking forward to receiving and considering proposals from prospective investors'. Enigmatically, the NOC declared, according to the Agip/Sirte paper, that it 'is willing to consider international gas pricing methods for the local gas market or oil for gas arrangements'.

Total gas production and demand are forecast to rise sharply, including a major increase in production of non-associated gas. By 2006 total production of associated and non-associated gas together is estimated to be increased to over 3bn cf/d. This compares with a preliminary estimate of gross production last year, according to Jonathan Green, of about 1.8bn cf/d. Of this, 30% was reinjected, 19% flared or lost, 38% locally consumed, and 13% exported as LNG.

Specific projects in a programme for execution in the period to 2010 include:

- development of gas from several already discovered fields, including the Attahady field in the central Sirte Basin;
- expansion of the national gas pipeline network by major projects in the next five years;
- the substitution of gas for fuel oil in all power generation; and
- extension of the gas pipeline network both eastwards and westwards to supply Egypt and Tunisia.

The Western Libya gas export project will have a radical impact on the European gas market. Existing agreements for gas imports to Italy by 2010 are already close to meeting prospective requirements, estimated on the basis of optimistic forecasts of demand and taking account of expected indigenous production. The addition of further imports of 8bn cm/y will raise the possibility that gas contracted for import into Italy will overspill into neighbouring markets. If this occurs it will inevitably be accompanied by weak prices. Realisation of the $5bn Western Libya project may rest therefore on an agreement for very low prices between the offtaker Snam and the producing consortium of Agip and NOC.

Aside from this problem for gas exports, a more general note of caution should be sounded about Libyan prospects. There can be no doubt from the presentations and enthusiasm of the Libyan government and NOC at the recent conference that the Libyans are keen to promote their re-entry to the mainstream of the international oil and gas industry. They are ready at this time to go the whole way towards establishing a favourable climate to attract both US and other major internationals to invest and collaborate in developing their industry. The bargaining, however, has yet to come in an international industry which is now, more than ever before, committed to cost-cutting and retrenchment.

*'Oil and Gas Investments in Libya', a CWC Associates conference held in Geneva on 19–20 April.

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Potential flexibility mechanisms include:

- exemptions or emission credits in cases where it can be demonstrated that domestic emission levels are being significantly overestimated by the techniques used;
- important cases might include the use of petrochemical feedstocks or applications of innovative emission reduction or 'capture' technologies; and
- extension of non-covered sectors through voluntary participation in the emissions trading system.

The level of any voluntary participation would depend on the advantage that those outside the emissions trading system expect to receive from joining it. For emitters, this would depend on the permit sale opportunities and obligations they would face under the emissions trading system, relative to the costs and obligations they would be subject to otherwise. This highlights the inter-relationship of the emissions trading system with other greenhouse response measures.

Issuing permits

The second discussion paper will address methods for the initial allocation of permits, potentially the most controversial component of an emissions trading system. The types of questions that need to be addressed include:

- Who should be the focus of permit allocation or other forms of compensation?
- What are the relative merits and drawbacks of various permit allocation methods, including auctioning and alternative grandfathering techniques?
- How can we minimise the significance of transaction costs?
- How can we best reduce uncertainty for future investment?

This paper is scheduled for release this month.

Crediting the carbon

The third discussion paper will focus on sinks. If climate change goals are to be achieved with the least overall cost to an economy, sequestration could well play an important role. Incorporating sequestration into a domestic emissions trading scheme effectively increases the range of abatement options available to firms. As such it may lead to lower prices for emission allowances.

Designing the market

The fourth discussion paper will address the legal and regulatory framework within which an emissions trading scheme will operate. An important component of this will be establishing mechanisms for assessing and ensuring compliance. It is important to understand that only parties to the Kyoto Protocol – that is, national governments – will have responsibilities and obligations under the Protocol. The international trading system currently being developed will establish rules which apply to the parties.

Australia and other like-minded developed countries would favour trading being fully devolved to the private sector. Emitters would then be responsible to national government for any emissions they produce within their respective countries. This responsibility would take the form of a requirement to surrender to the government a sufficient number of emission permits to cover their emissions.

Other issues to be covered in this paper include the design of permits to encourage fungibility, effective monitoring approaches, design of registries and penalties for non-compliance.

The final word

Australia, like other signatories to the Kyoto Protocol, has a challenging task ahead in order to meet its Kyoto commitments. Emissions trading, both domestically and internationally can play a role in minimising the costs of achieving these commitments.

*The Australian Greenhouse Office was established in April 1998 as the lead Commonwealth Government agency on greenhouse matters. It is responsible for the coordination of national climate change policy and for managing the delivery of major new and existing Commonwealth government greenhouse programmes. The AGO website can be visited at **www.greenhouse.gov.au** (the National Greenhouse Strategy can also be downloaded from here).

Novel Banff FPSO concept

Conoco's Banff oil field in the central North Sea shipped its first load of crude in February this year. The project has attracted interest because of the novel wedge-shaped hull design used for the field's floating production, storage and offloading (FPSO) vessel. It is also unusual in that a six-month early production phase was used to assess reservoir performance before the development plan was approved. Such early production phases could become more common as North Sea discoveries become smaller and more complicated to develop, writes *Jeff Crook*.

Located in blocks 29/2a and 22/27a, the Banff field was discovered by Ranger Oil in 1991. The field was originally regarded as marginally economic with recoverable reserves of oil estimated to be between 20mn and 110mn barrels. In 1995, it was decided to install an early production system for a six-month period to assess the performance of the reservoir before a final decision was made on field development. The data from this early production phase also allowed the partners to optimise the development plan.

The early production system involved two subsea production wells connected to the *Sedco 707* floating production unit, a semi-submersible drilling rig that had been modified to accommodate fluid processing facilities and other production equipment, and the *Stena Savonita* shuttle tanker. The system was operated by the TAP Alliance, a joint venture formed between Schlumberger, Sedco Forex and Coflexip/Stena.

Production fluids flowed from the wells on the seafloor to the *Sedco 707* where they were processed. The stabilised crude was then pumped to the shuttle tanker which maintained its station by means of dynamic positioning. When the tanker was fully loaded with 750,000 barrels of crude, the wells were shut in, and the vessel sailed to port to discharge its load.

During this six-month early production phase, the two wells produced at a continuous rate of 35,000 b/d, yielding over 5mn barrels of crude oil. This performance, along with other studies, proved the potential for further development. In addition, the estimate of the field's recoverable reserves at the end of the early production phase was revised to 60mn barrels of oil and 39bn cf of associated gas.

Development plan

The Banff development plan consists of subsea wells connected to the newly built FPSO *Ramform Banff*, with oil exported by shuttle tankers and associated gas exported by a pipeline connected to the Central Area Transmission System (CATS). Initially two double-hulled tankers – the *Wilma Yukon* and *Nordic Svenita* – will transport oil to shore. This will be reduced to one vessel as production declines. Offshore loading takes place from a single anchor loading mooring (SALM) system.

The *Ramform Banff* is owned and operated by Petroleum Geo-Services (PGS) Ltd and is based on the Norwegian Ramform design that has been successfully employed by PGS for some of its seismic vessels. Conoco says that the wedge-shaped hull, with its wide stern, enables the vessel to 'carry large deck loads without compromising stability or safety. It also provides capacity to reconfigure or add processing packages for incremental or third party oil production.'

PGS echoes these comments and points out that the FPSO was built in half the time and using a third of the steel of a 'conventional' FPSO of equivalent size. The vessel can store 120,000 barrels of processed oil and will process 60,000 b/d of oil and associated gas from Banff. The safety of the vessel has been enhanced by a firewall which separates the production area from the process area, together with a fire and blast protected escape tunnel.

The *Ramform Banff* was built at the Hyundai Mipo yard in South Korea and was fitted out at the Aker McNulty yard in Newcastle. The scheduled date for first oil was June 1998, but the project was delayed as a result of a decision to upgrade the vessel to handle fluids from Ranger's Kyle field. This required the processing capacity to be increased from 60,000 b/d, the plateau flow from the Banff field, to 95,000 b/d.

When Banff came onstream, Reidar Michaelsen, PGS Chairman and Chief Executive Officer said: 'We are extremely pleased to have achieved this momentous milestone. The Banff project is a perfect example of the success that can be achieved through oil company and oil service company cooperation and the use of advanced technology. We are pleased to be an integral part of this success story.'

PGS says that the *Ramform Banff* is contracted by Conoco and its field partners for the life of the field (around 8 years) under a tariff-based compensation plan. This is the third FPSO in the PGS fleet. The company also operates the *Petrojarl Foinaven* in the Foinaven field, West of Shetlands, and the *Petrojarl 1* in the Talisman Energy operated Blenheim field in the North Sea.

Multi-lateral wells access marginal reservoirs

The success in the North Sea of multi-lateral well engineering in draining marginal reservoirs that would otherwise be uneconomic is not only extending the life of fields in the ageing UK Continental Shelf (UKCS) but it offers the possibility of global applications for this technology. Also, the process applied to the development of multi-laterals can be applied to any new technology in many environments, writes *Jack Winton* of KCA Drilling.

Three areas of application have been identified where a multi-lateral approach can boost economics and reduce the risk and exposure associated with these types of wells. Firstly, this technique can be applied by combining two marginal locations, such as the less prolific hydrocarbon bearing sands, in one slot, thus sharing the high costs of a new well when side-track candidates are not available. Apart from the savings made by combining the locations in one slot, the total uncertainty about the well's economics are reduced.

A second application is the drilling of 'premature' side-tracks from existing producers. This approach accelerates production. In theory it does not increase the ultimate recovery since the well could be drilled at a later stage, but if the field is only economic when tied in with other fields then this process may be necessary to ensure the field lives are consistent.

Finally, the multi-lateral technique offers the opportunity to combine high uncertainty appraisal locations with lower risk development drilling. The reservoir would normally be developed in two stages. First, a proven area would be drilled after which appraisal drilling would determine further scope for the reservoir. By combining the first development well with an appraisal leg testing the extent of the accumulation, both oil production and important information can be accelerated. The value of this information is high in assessing the future of the accumulation. The effect this information has on production forecasting and the economic end of field life is considerable.

Some additional benefits are associated with horizontal multi-lateral legs. The pay zone that is achieved with two horizontal legs can be higher than with one, as there is a constraint on the finite length of a single horizontal section that can be achieved in one well. Moreover, if uncertainty exists on the optimal direction for the horizontal leg (for instance in cases where separate sand bodies need to be encountered), a multi-lateral approach offers an extra degree of freedom, minimising the risk associated with drilling the well.

Tern Alpha

The Tern Alpha is a fixed installation in the East Shetland Basin of the northern North Sea approximately 500 km from Aberdeen. Shell UK Exploration and Production (Shell Expro) operates the field on behalf of Shell/Esso which are 50/50 partners. KCA Ltd is the lead drilling contractor. First oil was produced in June 1989 and of the 30 slots available 10 have yet to be utilised. Tern forms one of five installations with associated subsea developments making up the Shell Expro Northern Business Unit (NBU).

Oil is produced from the Middle Jurassic deltaic sands of the Brent Group via the platform with gas lift and water injection facilities. STOIIP and recoverable reserves are currently estimated to be some 600mn barrels and 295mn barrels respectively.

Production has been focused on the Etive, the most prolific reservoir sand in Tern. Etive production predominates in conventional wells completed on all reservoir units. Consequently, the contribution from poorer quality formations has been marginal. With Etive development essentially complete, activity has shifted to multi-lateral technology as a cost-effective strategy for enhancing the productivity of the poorer quality Upper Ness and Rannoch formations.

This in-field strategy is coupled with a sustained focus on Near Facilities Potential (NFP) opportunities, for example the Triassic. The challenge for NFP is to quantify the value of potential hydrocarbon prospects quickly, thus enabling optimum incorporation into the field development plan.

Four multi-lateral wells have been constructed on Tern since late 1995. Each well has been designed to fit the required application but has utilised the same conceptual design theme. This design was originally based on standard oilfield technology applied using a novel approach. The four wells have evolved this initial concept using new technology as it has become available.

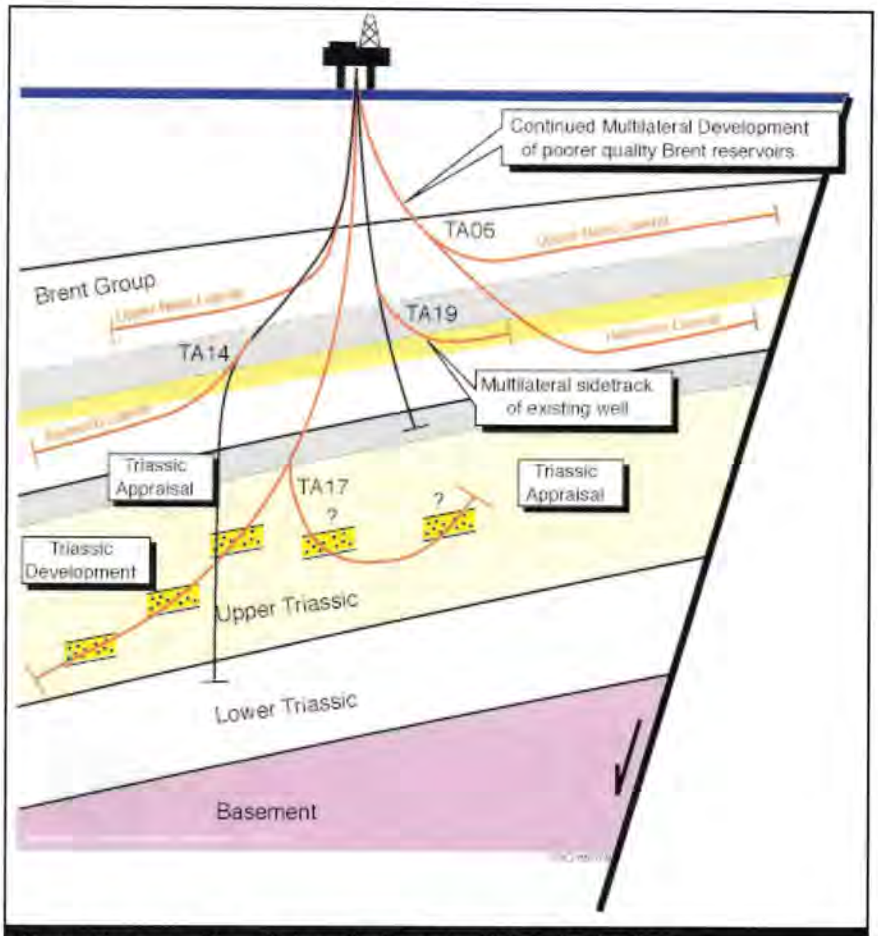
The first multi-lateral well on Tern, TA-14, had a threefold objective. The first was as an appraisal well to examine and test the undeveloped Triassic. The second objective was to develop the Rannoch and Upper Ness formations in the Brent sequence and the third was to use the (then new) multi-lateral well design to implement this. The pilot hole was drilled as an 'S' shape well through the Jurassic and Triassic reservoirs to basement. Following the successful testing of the Triassic, the second and third objectives were met by drilling two cased hole horizontal laterals from the pilot hole. The success of TA-14 led to the confirmation of the drilling sequence for further applications of this technique.

TA-19 was originally planned as a side-track following water breakthrough. However, as a result of remedial work, net oil production increased and the decision was made to delay abandonment of the still commercial upper reservoir and side-track while retaining production capability from the main bore. Again, a horizontal lateral was drilled to develop the Brent sequence and the well was subsequently completed as a cased hole dual lateral with comingled and selective production available.

The third multi-lateral well, TA-17, was designed to develop reserves proven in the TA-14 pilot hole and appraise the Triassic in an adjacent block. As a new well it was possible to make use of a pre-cut window and latch coupling in the production casing. The main bore was drilled as a horizontal well intersecting as many of the uncemented Triassic channel sands as possible. The upper lateral was drilled from the pre-cut window as a horizontal appraisal well with a final inclination of 100° proving further reserves.

The recently completed fourth cased hole multi-lateral well, TA-06, was again a new well making use of a pre-cut window. This was a technological replica of TA-17 repeated on a similar application to TA-14 whereby the Rannoch and Upper Ness formations in the Brent sequence were developed.

All four wells are currently producing and in the drive to develop multi-lateral technology, lessons from planning, implementation, evolution, and management have been generated.



Moving the wave with multiple applications of multi-lateral technology

Multi-lateral learning points

Within the NBU of Shell, KCA Drilling maintains an easily accessible, lessons learnt database to ensure these lessons are recorded and mapped. This data is available to other asset teams within NBU to ensure there is a cross- fertilisation of ideas and to allow the current Tern team's successors access to the historical learning points. Steps are currently being taken to incorporate these and other learning points into an Internet-based learning database.

The development of multi-laterals on Tern has generated a large number of highly specific learning points and details of these are contained within paper IADC/SPE 39353 available from the Society of Petroleum Engineers. The more generic learning points include:

- The project management team must have clearly defined roles and targets to ensure all areas of the planning stage and the operational stage are covered.
- The use of trials and dry runs ensures new techniques will work or will highlight potential failings.
- Detailed engineering drawings of downhole equipment and tools should be available offshore and onshore to ensure all parties are aware of exact depths.
- The transition joint liner lap into the production casing should span the lateral window with no couplings above the base of the window to allow efficient removal at a later date.
- Cementation of the lateral liner is critical for milling support during the transition joint liner lap removal and for subsequent junction integrity. Not only does the production casing and lateral liner cement provide isolation from the formation, the liner cementation provides stress support during the milling process.
- Whipstock design must include built in contingency for recovery in the event the primary recovery method proves unsuccessful.
- Techniques should be employed to ensure a datum(s) can clearly be identified in the well at whatever stage of its lifecycle it is in.
- Debris management is critical and where possible techniques to reduce the generation of debris should be used. It should be recognised that debris will always be created with these techniques and as such should be planned for and managed.

Multitude of benefits

Benefits of the multi-lateral technique are pervasive. Savings on TA-14 and TA-06 type wells can be achieved by applying the technique in a combination of variable and low quality reservoirs in one single well.

Slot constraints can be alleviated using the TA-19 technique by side-tracking existing producers at an earlier stage. This strongly accelerates production while safeguarding the often underestimated tail production from the mother borehole.

By using the TA-17 technique, appraisal and development objectives can be met from one borehole, which would have otherwise required two new wells.

The process applied to the development of multi-laterals on Tern can be applied to any new technology in many environments. This process will continue to be applied for future applications on Tern, such as water injection multi-lateral wells and coiled tubing drilling.

Measurement of aviation fuel thermal stability

The civil and military engine and airframe manufacturers continually quest for more performance, reliability and efficiency to meet both technical and commercial aims. This has led, in turn, to an increase in the temperatures to which turbine fuels are subjected.

Thermal stresses on fuels in aircraft engines can result in the unwelcome formation of insoluble carbon deposits, such as lacquers, in the aircraft's fuel system. These deposits adversely affect reliability and maintenance requirements.

In order to move forward, new improved fuels are desired and better ways of measuring their performance under realistic conditions are required.

The production of fuels, which are less affected by thermal stresses and consequently have greater thermal stability, requires a standardized test procedure which gives a quantitative result that correlates with real life conditions. Unfortunately current approved methodology from the 1960s does not meet the new requirement. However, 10 years of research by Shell and current developments by Stanhope-Seta have led to the development of new advanced instrumentation in the form of the Seta HiReTS Tester.

The last 30 years

The currently specified test methods for assessing the thermal stability of turbine fuel were first developed 30 years ago and rely on fuel passing over the outside of a specially prepared heated tube, under laminar flow conditions. The result of the test is ascertained by rating the deposits formed on the tube for colour and collecting any carbon deposits by a filter.

The test itself takes 150 minutes but in addition significant time must be allowed as the test is extremely operator intensive during initial set up, final cleaning and disassembly.

These tests are widely used and well known but the test is carried out in unrealistic laminar flow conditions and the result is not quantitative and relies on the operator to rate the result optically.

In addition lacquer distribution is fuel dependent and unpredictable, and hence a single measurement or optical assessment may fail to distinguish between two fuels of different stability.

The Seta HiReTS Tester

This new instrument tests the fuel for thermal stability under realistic turbulent flow conditions and gives a quantitative result. Turbulent flow is usually defined by Reynolds Number, hence HiReTS refers to High Reynolds Number Thermal Stability. Calculations and control functions are implemented by an integral computer.

The instrument pumps a constant flow of fuel through a heated stainless steel capillary tube. The heating of the capillary tube is controlled to maintain a constant fuel temperature at the output of the capillary tube. The flow rate and capillary bore ensures that turbulent flow is maintained.

During the test, the temperature of the outside of the capillary tube is continuously checked and recorded at nine points using an infra-red optical pyrometer. The formation of lacquers and fuel degradation products acts as a thermal insulator between the cooler fuel and hotter capillary tube. This causes an increase in temperature of the capillary tube which is measured by the pyrometer. The apparatus computes the difference between the minimum and final temperatures to give a HiReTS number that correlates with real performance data and can be used in specifications.

The instrument is highly automated and operator time is limited to changing the capillary tube. Test time is 120 minutes. However, further research indicates that this may be reduced to 60 minutes.

New HiReTs Tester

Specifications and standardization

The aviation industry is understandably very conservative in adopting new technologies due to safety concerns. The guardians of test methods and specifications in the UK are the IP and DERA, and the ASTM J sub-committee in the US. The road to changing a specification to include a new procedure, such as the HiReTS, is involved as both technical and commercial inputs have to be addressed in a new test method.

As this new procedure will be widely used in the future throughout the world, an international task force has been set up to review the proposed procedure. Already experts from 11 countries are participating.

The IP and the ASTM have commenced working together to produce a joint HiReTS standard test method. The plan is for the IP to publish a Proposed Method in 2000, and a Full Method with precision in 2001.

The new test method will be initially offered as an alternative to the existing test method, however this application of technology is such a step forward that it may be necessary for industry to consider this procedure as the referee method within a few years.

Mike Sherratt
Director of Research, Stanhope-Seta;
Member of IP Test Methods Standardization Committee

Oil price hits Canadian oil development plans

Almost $20bn has been slated to develop heavy oil and oil sands deposits in Canada over the next decade. *Gordon Cope* in Calgary examines how recent oil price fluctuations have impacted plans.

At Syncrude's open-pit Base mine in northeast Alberta, giant trucks trundle across the barren landscape, each one carrying enough black, gooey oil sands to fill two DC-10 jumbo jets. They make their way to an extraction plant, where their cargo is converted to Syncrude Sweet Blend (SSB), a 33° API synthetic crude oil.

Oil sands are deposits of bitumen (petroleum in the solid, or semi-solid state), mixed with unconsolidated sand. In its raw form, it closely resembles the heavy, black material used to surface Macadam (tar) roads. Heavy oil is particularly viscous petroleum, measured in the range of between 8° to 9° API. It contains a high percentage of bitumen.

Both oil sands and heavy oil are very difficult to extract using conventional, subsurface techniques. Oil sands require large, upfront investments in extraction and processing equipment, and heavy oil production often requires closely spaced wells and enhanced oil recovery techniques, such as steam injection. But, for whatever it lacks in producibility, it makes up for in magnitude.

The Canadian Association of Petroleum Producers (CAPP) estimates that the oil sands region in Alberta contains 300bn barrels of recoverable oil, out of total reserves of 2.5tn barrels. Venezuela also contains immense deposits of oil sands and heavy oil, about 289bn barrels of recoverable reserves.

The total production of synthetic crude from the Syncrude oil consortium, located near Fort McMurray, Alberta, and the nearby Suncor Energy's plant averaged almost 330,000 b/d in 1998. In-situ heavy oil production, mostly centred around Cold Lake, Alberta, added a further 500,000 b/d. Together, oil sands and heavy oil account for almost half of Canada's total oil production. Venezuelan production, which currently hovers near 2.84mn b/d, is mostly heavy crude. In all, oil sands and heavy oil production represent approximately 5% of global output.

Following the 1996 announcement by the Alberta government to make new projects and major expansions virtually royalty-free until capital costs are repaid through cash flow, over C$21bn in new investments were announced. Venezuela, which opened its resources up to outside investments, had six joint venture projects worth approximately $6bn due to start in the next year. Some of the planned projects included:

- Syncrude Canada targeted C$600mn to debottleneck its upgrader and bring the Aurora mine on production by mid-2000. Production would be boosted from 225,000 b/d to 257,000 b/d by 2001. A C$3bn upgrader was scheduled for completion in 2003. The fourth and final stage of expansion was scheduled for start-up in 2006, and would take total production to at least 425,000 b/d.
- Suncor Energy's Millennium Project proposed to spend over C$2bn to double output at its Steepbank mine to 210,000 b/d by 2002.
- Shell Canada earmarked C$1.2bn to launch the 50,000 b/d Muskeg River oil sands project north of Fort McMurray by as early as 2002. Shell also planned to include a C$1.9bn heavy oil upgrader at its Scotford refinery near Edmonton and a C$500mn pipeline to connect them.
- Mobil Canada unveiled a C$2.5bn oil sands project for its 1.4 bn barrel-recoverable reserves deposit near the Syncrude and Suncor complexes in the Fort McMurray region. Scheduled for completion in 2003, the Kearl mine and extraction plant would have a capacity of 100,000 b/d.
- Imperial Oil, which produces approximately 115,000 b/d of heavy oil from its Cold Lake field, broke ground for a 250-km bitumen pipeline from Cold Lake to the Hardisty, Alberta terminal. The C$250mn pipeline, scheduled for completion in 2000, would have a capacity of up to 700,000 b/d of blended bitumen.
- A joint PdVSA and Conoco project called for up to 530 horizontal wells to drain heavy 9° API oil from Venezuela's Orinoco oil sands deposit.

After the plunge

Because of the large scale and long-term nature of oil sands and heavy oil developments, many of the above projects were planned when the price of West Texas Intermediate (WTI) stood at $27/b, and returns on invested capital hovered in the 18% range. In late 1997, however, due to the collapse of many Asian economies and the inability of Opec to curb production, prices fell dramatically, to the point where, in February 1999, prices hovered in the $10/b range.

Heavy oil was hit even worse. The differential for benchmark Canadian Bow River heavy oil (the discount refiners seek due to added costs of processing), rose to $7.32 by early 1998, and petroleum companies in Canada began to turn off marginal production. 'At least 50,000 b/d of Canadian production was shut-in,' says Steve Kelly, a researcher at refining consultants Purvin & Gertz, and author of *Canadian Heavy Oil Crude Market: Adapting to New Challenges*.

Low oil prices also put oil sands projects, which have a break-even price of approximately C$13/b, in jeopardy. In January 1999, Syncrude's Chief Executive Officer Eric Newell announced that the C$3bn upgrader plan would be delayed a year, to 2004. Mobil Canada postponed its C$2.5bn Kearl oil sands project for two years. Broken Hill Proprietary walked away from its 25% option on Shell Canada's proposed C$1.4bn Muskeg River oil sands project. Venezuela found itself caught between its agreement to stick to

Opec cuts of 150,000 b/d and the needs of its cash-strapped central treasury.

The price rebounds

What a difference a month or two can make, however. Since mid-February, the price of crude oil on the New York Mercantile Exchange rose 45% to close above $16/b by the end of March. Prices for Bow River benchmark heavy oil also shot up 40%, and the differential closed to approximately $1.60/b.

That same month, when Suncor Energy received conditional approval for the C$2bn expansion of its Fort McMurray operation, it announced that construction would begin immediately. PanCanadian Petroleum brought back 3,000 barrels of shut-in heavy oil production.

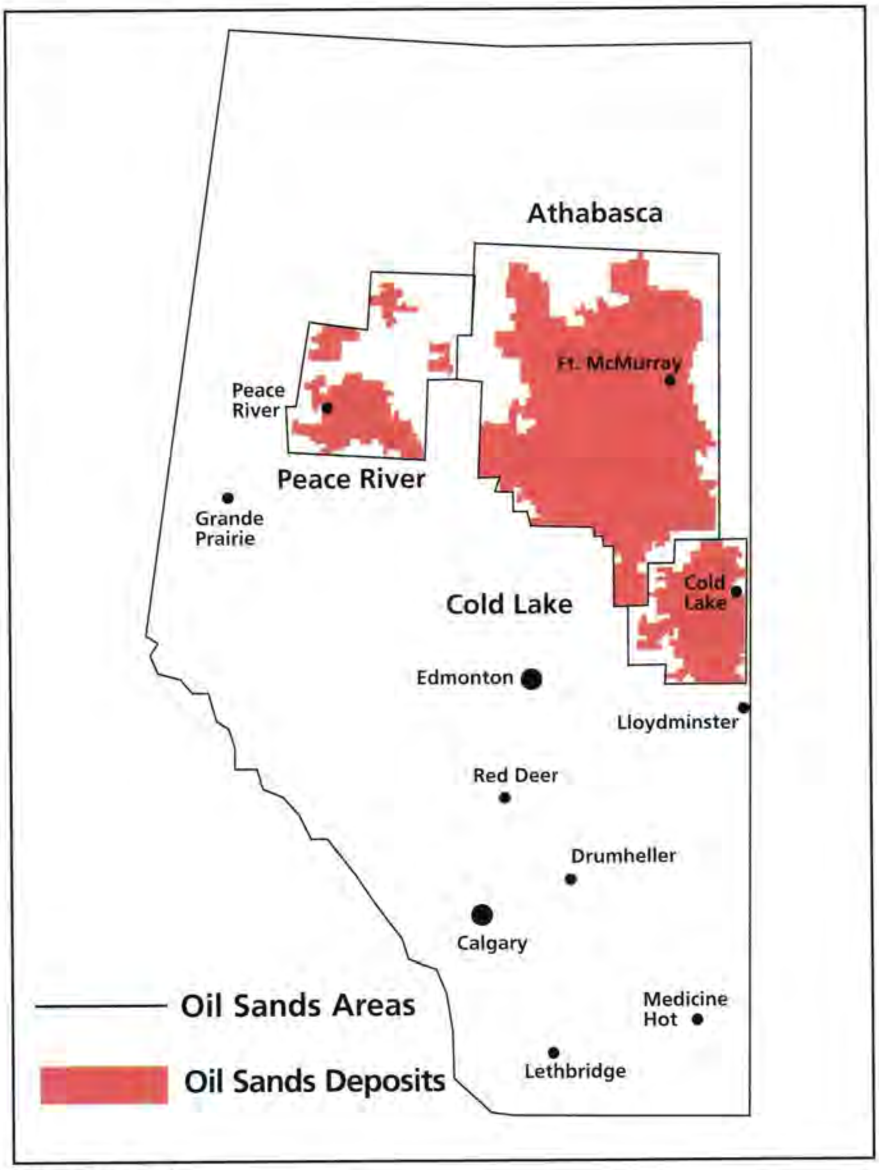
The wild life

As the shock of low oil prices recedes, however, oil sands projects must deal with another concern as production rises – increased environmental impact. In addition to 225,000 b/d of Syncrude Sweet Blend, Syncrude also produces 1,500 tonnes of sulfur, 3,000 tonnes of coke and 500,000 cm of tailing water. The currently unusable waste products end up in a 15 sq km storage pit for reject sand, a 5 sq km tailings lake for waste water, and a 1 sq km pit for coke. 'The area has largescale disruptions happening,' says Tom Marr-Laing, Manager of the oil sands group for the Pembina Institute for Appropriate Development, a non-profit environmental watchdog. 'We're talking hundreds-of-kilometres areas. I imagine you can see it from outer-space.'

'We take the issue very seriously,' says Syncrude's Peter Marshall. 'We've never had an environmental fine or control order. We've invested an awful lot of money over the years (C$117mn since 1976), to create unique technologies to speed up reclamation and return the habitat to a self-sustaining state.'

To date, Syncrude has reclaimed over 2,500 hectares of land and planted more than 1.8mn tree and shrub seedlings, and plans to reclaim another 2,000 hectares over 10 years. The company recently received a citation for reclamation award from Albert Environmental Protection for land reclamation planning. 'When we move to the Aurora mine, we'll be reclaiming at the same speed as we mine,' says Marshall.

'Over the last 25 years, no lands have been recertified (by environmental officials in the Alberta government),' counters Marr-Laing. 'Their plans look promising, but until they can prove what the plans can do, we're quite critical.'



Alberta oil sands

Greenhouse gas emissions are a more serious concern. Natural Resources Canada predicts that Canadian greenhouse gas emissions will be about 45 megatonnes higher in 2010 than predicted. Oil sands projects account for 27 megatonnes, or 60% of the emissions growth.

'Greenhouse gas emissions from oil sands are certainly comparable to conventional North American production, and lower than some of the imported crude, such as Venezuela's,' says Marshall. 'Over the next five years, we're going to invest almost C$500mn in more energy efficient equipment and processes. Our CO_2 emissions are going to drop 29% between 1990 and 2007.'

'They are willing to commit technically to keeping carbon dioxide levels static,' says Marr-Laing. 'But nitrous oxide levels (which contribute to low level ozone and acid rain), are between 75 t/d and 80 t/d, and they're forecast to be over 200 t/d at three times current production levels.'

New technologies

In order to make oil sands mining more profitable, Syncrude intends to use new technologies to reduce costs. 'We spend over $100mn per annum on research, and we've had some exciting new breakthroughs,' says Marshall. 'Hydrotransport (the oil sands are mixed with water and shipped in suspension by pipeline) allows us to move out to bigger reserves, and low-energy extraction has enormous impact on greenhouse gases and lower operating costs. We're hoping to get costs down to C$12/b by 2000.'

A Calgary-based company recently made a technology breakthrough that may have even more of a long-term impact on oil sands and heavy oil, however. Upgraders have traditionally been engineered to 100,000 b/d or more capacity to take advantage of economies of scale. At a cost of up to $18,000 per barrel capacity however, such refineries come with a price-tag of well over $1bn, putting them out of reach of all but the biggest industry players.

Now, Ensyn Energy Group has come up with a mini-processing plant that can efficiently extract up to 10,000 b/d of synthetic crude from oil sands (see p17). 'Any size producer can use this technology, but the most important thing is that small producers can use it,' said Dee Parkinson-Marcoux, President of Ensyn Energy Group. A 2,000 b/d upgrader would cost approximately $20mn to build, and operating costs are in the range of $1/b. Gulf Canada recently purchased a $19mn plant to test the process on its reserves.

Doffing the hair shirts

The short-term outlook for oil sands is looking decidedly brighter. 'Syncrude Sweet Blend fetches a premium on West Texas Intermediate of around 90 cents Canadian (because of its low sulfur content),' says Marshall, who notes that most of the oil sands synthetic oil production serves as feedstock to Canadian refineries owned by partners in the project, including Imperial Oil and Petro-Canada. 'We are in the black – we have positive cash flow.'

Conditions are also improving for heavy oil. 'The low oil prices took a lot of heavy crude off the market and caused the differential to narrow,' notes Purvin & Gertz researcher Steven Kelly. 'Now, with the absolute price rising, we expect to see more widening of differentials, but we're still looking forward to a tight year.'

About one-third of Canadian heavy oil output goes to roadway asphalters, and summer demand is expected to be relatively strong. The other two-thirds goes to refinery markets, primarily in the US midwest. Some of the largest consumers are Mobil and Amoco's cokers in the Chicago region, and Koch's refinery in Minneapolis.

The biggest competitor to Canadian heavy oil production is Venezuela. 'Venezuela will market into the Gulf Coast region,' says Kelly. 'It doesn't affect the Canadian market share (in the US midwest), but it will drive the global differential, and that will flow back to Canada.'

In the longer term, synthetic crude and heavy oil face production limits. 'On the demand side, I see a ceiling about 1.5mn b/d,' says Onno DeVries, a spokesman at CAPP. 'Over 1.5mn b/d, you're starting to push the envelope of the primary market (refiners in the US midwest).'

DeVries doesn't see Canadian production rising much above 2mn b/d, however, even as conventional North American production continues to decline. 'It's a question of the quality of reserves – you need good concentrations to make it economic.'

Regardless, Canadian oil companies will look to heavy oil and oil sands as their large fields peter out. 'It was crucial that many of the major oil companies in Canada make the leap to profitable oil sands production because conventional oil development in the mature Western Canadian Sedimentary Basin has become a game of small increments,' said James Stanford, President of Petro-Canada, a senior partner in the Syncrude oil sands consortium.

Likewise, with heavy oil. 'PanCanadian's big potential lies with Christina Lake, which has 2bn barrels of recoverable heavy oil, most of which will have to be artificially lifted with Steam Assisted Gravity Drainage,' says spokesman Al Boras. 'It's a tremendous prospect, and we foresee as much as 50,000 b/d production – but the price of oil has to be right.'

New technology revolutionises fuels testing

The Institute of Petroleum (IP) and the American Society for Testing and Materials (ASTM) are actively involved in defining acceptable fuel test methods to determine if fuels comply with the specifications laid down by bodies such as API (American Petroleum Institute) and BSI (British Standards Institute). *Roy Broadbank,* Managing Director of Sartec,* outlines how recent technological developments have revolutionised fuels testing equipment, reducing testing times and costs while improving accuracy.

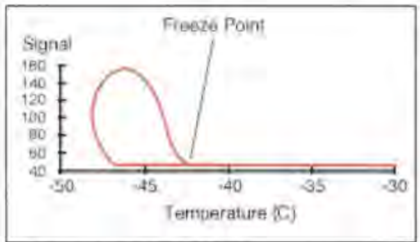


Figure 1: Freeze point

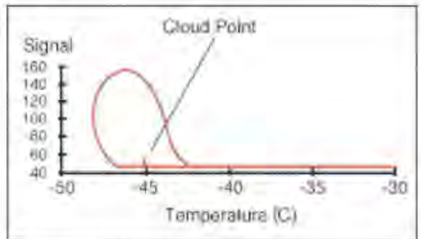


Figure 2: Cloud point

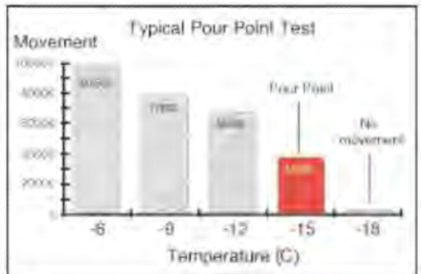


Figure 3: Pour point

Of all the tests undertaken when analysing fuels and lubricants three of the most important are: freeze point, cloud point and pour point. Each is vital in determining the parameters under which such fuels can be safely used without the risk of crystallisation or wax precipitation which can block engine fuel systems.

Freeze point is an important specification for aviation turbine fuels. Maximum freeze point values are set for all types of jet fuels as a guide to the lowest temperature at which the fuel can still be used without the risk of crystallisation. Crystallisation can lead to fuel starvation through clogging of fuel lines and filters in aircraft. It can also reduce the amount of fuel available to the engine due to retention of solidified fuel in the tanks.

The freeze point test involves cooling the fuel until crystals form throughout the sample and recording the temperature at which all crystals disappear on rewarming the fuel (see **Figure 1**).

Cloud point is an important specification for diesel and other distillate fuels. It is the temperature at which the first wax crystals appear in a sample when being cooled. Maximum cloud point limits are often set on diesels, heating oils and certain lubricant base oils. It is a useful indicator because wax precipitation can block fuel lines and filters causing malfunction or stalling of diesel engines (see **Figure 2**).

Pour point is a critical specification for lubrication oils, and is sometimes specified for other fuels. The pour point of a fuel or lubricant is an indication of the lowest temperature at which the petroleum product can be pumped. The pour point test involves cooling the fuel and determining the lowest temperature at which the sample can still be moved by tilting the test tube horizontally for five seconds. Whereas cloud point indicates the beginning of a cold flow problem, pour point is a guide to the lowest temperature at which a fuel can be pumped (see **Figure 3**).

Alternative test methods

Laboratories are always looking for new analytical equipment that can improve testing throughput, that are easier to use and require less capital to purchase. This is particularly the case in laboratory fuels testing.

Conventional measurement technologies require huge cryogenic refrigerators which have to be floor-mounted and typically weigh over 250 kg. These refrigerators are maintenance intensive and generate a lot of unpleasant noise and heat into the laboratory. Furthermore, different models are required for different tests, resulting in a high capital outlay.

The use of a new light scattering technique – developed by Phase Technology, Richmond, Canada – for the measurement of freeze, cloud and pour points is now regarded as an acceptable alternative test method by the IP and ASTM. However, this is not yet accepted as the ultimate standard for the specification. The approvals cover the test methods as well as product specifications relevant to aviation turbine fuels, diesels and lubricants.

In addition, this new technology has gained the approvals of major industrial and military organisations such as the Airport Joint Fueling Systems Checklist, International Air Transport Association (IATA), Ministry of Defence and the US military. It has now become the most widely accepted technology for automatic freeze, cloud and pour point measurements.

This new technology has revolutionised the conventional measurement methods in many ways. To begin with, the new analysers, complete with an internal cooler, take up only 30 cm of laboratory bench width and weigh just 20 kg. One analyser can perform all three functions of freeze, cloud and pour point measurement. The Phase Technology ASTM-approved Petroleum Analyser, see **Figure 4**, is an example of the new technology in practice.

The precision of the new technology

Figure 4: The Phase Technology ASTM-approved petroleum analyser

improves on that offered by conventional methods – in most cases the precision is more than twice as good. This helps refineries maintain high quality production without wasteful use of valuable stocks and over-refining.

The new instrument is extremely easy to operate. It requires approximately 15 to 30 seconds of operator time to start the test sequence. The instrument then takes over and completes the determination in between 3 and 20 minutes, depending on the type of test being conducted. Most of the freeze and cloud point tests are completed in 3 to 5 minutes. In comparison, the conventional test methods could take hours to complete and demand the attention of the operator for the most part of the tests. For example, the light scattering method completes the pour point determination of automatic transmission fluids in the –54°C range within 20 minutes. A similar test by conventional methods would take 5 to 6 hours and end up with a less precise result. Such fast analysis time dramatically improves productivity in laboratories.

This technology has allowed the development of online process petroleum analysers which enable freeze, cloud and pour point to be continuously measured. Problems with the refining process can therefore be identified earlier and corrective action can be taken sooner, thereby reducing wastage even further.

Light scattering technique

The basic principle of the light scattering technique is to continuously monitor the behaviour of the sample while it is subjected to prescribed temperature changes. A small sample (150 µl) of the test material is placed inside a sample cup with a polished bottom which serves as a reflective surface (see **Figure 5**). A matrix of 130 optical sensors is placed perpendicularly above the sample to monitor sample clarity. A lens system is placed between the sample and the optical sensors. The lens system is focused in such a way that the image of the sample is projected onto the sensors. Sufficient sensors are available to map out the whole image.

A visible light beam is directed onto the sample at a specified angle. When the liquid sample is clear, this incident beam is reflected at the mirror surface and the resultant reflected beam impinges onto the black surface of the test chamber. The light energy is absorbed by the black surface.

When wax crystals appear in the sample, the reflected beam is scattered by the solid–liquid phase boundaries and a significant amount of scattered light impinges onto the lens. Even minute hydrocarbon crystals, regardless of their locations in the sample, will be detected by the sensors.

A very critical requirement of the test is the monitoring of phase change in the entire cooled sample, not just a portion of it. There is no blind spot in this optical arrangement; whereas other automatic or automated methods often involve considerable blind zones because those optical designs cover only part of the sample volume.

Sample warming and cooling are tightly controlled by a thermoelectric cooler. All the measurements are direct observations – there is no need for correlation. The temperature of the sample is monitored by a research grade laser-trimmed platinum resistance thermometer. The onboard microcomputer accurately controls the sample temperature with the help of the temperature sensor operating as a feedback device.

Electronic cooler

Development of electronic coolers is one of the main factors in reducing the size of the new analysers. This technology requires only one thermoelectric device to supply all the cooling needs. It is a small, custom-designed solid state device made up of hundreds of tiny thermocouples, each supplied with an electric current.

The heat from one surface of the cooler is continuously transferred to the opposite surface; thus creating a cold and a hot surface. When the heat of the hot surface is removed by conduction, additional thermal energy can be transferred from the cold surface to the hot surface.

This cooler can maintain the sample temperature at –84°C when a good heat sink is available. In such a cooling system, no CFCs (chlorofluorocarbons) or refrigerants are used. Also, there are no moving parts in the cooler, significantly improving the reliability of the system.

Another advantage of the electronic cooler is that it can function as a heater by reversing the current. The switching of the heater/cooler function can be performed in a matter of microseconds, enabling the analyser computer to control sample temperature with extreme precision. At the end of each test, the sample is heated up to ambient temperature within a few seconds.

The key to development

As the article shows, the key to the adoption of innovative and cost effective test methods is demonstrating to the standards bodies such as the ASTM and IP that the new methods provide superior or equivalent results to existing techniques.

Close cooperation between the developers of new techniques and the standards bodies is vital to giving the industry the cost-effective testing it requires.

**Sartec Ltd is the UK distributor for US fuels testing equipment company Phase Technology Petroleum Analysers.*

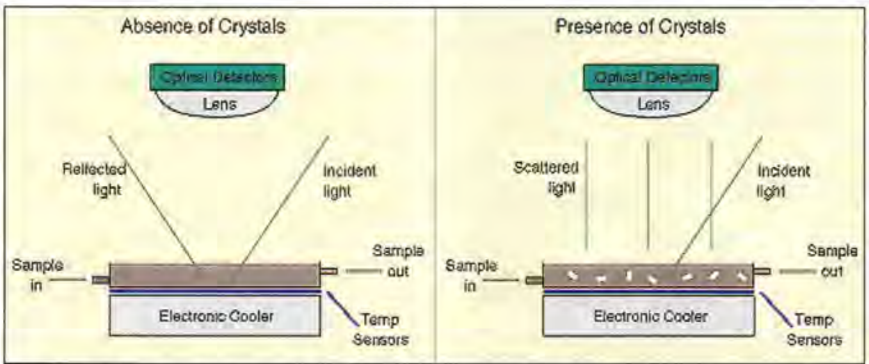


Figure 5: Light scattering technique for the detection of crystals

Looking good from Houston

When nearly 45,000 upstream people, including some 7,600 from 94 countries outside North America, gather to listen to more than 300 presentations in four days at the annual Offshore Technology Conference (OTC), it is possible to determine an overall sense of the industry's mood and direction. If the perception this year was an accurate reflection of the future shape of the offshore industry, new technology will continue to reduce costs and more alliances will occur – with associated job losses, especially in the supply sector – whatever happens to oil prices, reports *Philip Algar* recently in Houston.

The massive turnout was predictable but many UK visitors were surprised by the Americans' widely held view that the worst of the crisis is now over and that crude oil prices – notwithstanding occasional volatility – will remain close to current levels. The optimism, as in 1998, was based largely on activities in the deepwaters of the Gulf of Mexico where long-term contracts for drilling and associated work are not affected by the price fall. Equally, there are high hopes for deepwater projects offshore West Africa and Brazil. Many US participants believe that Opec will sustain production discipline but some optimism succumbed to detailed analysis of fundamentals, suggesting that the US, aware of the importance of sentiment, wants to talk up prices and prospects.

US vs UK experience

Another reason for the different levels of confidence between the US and UK was offered by Sir Ian Wood, Chairman of Scottish Enterprise and of the Oil, Gas and Petrochemicals Supplies Office, who once again led the UK delegation in the absence of a government minister. He argued that there was a clear difference between the two sides of the Atlantic in the timing of the reaction to the downturn in crude oil prices. The reaction in North America, which began last July,

was swift and decisive. 'There was a huge reduction in the workforce and cutback in manufacturing plants and servicing but the rig count seems to have bottomed out,' he said. If West Texas Intermediate prices remained around $16–17 per barrel, 'then you will see some light at the end of the tunnel very soon'. Sentiment was changing.

The North Sea was lagging about six months behind the US. 'We had a fairly long pipeline, a number of bigger projects and the downturn really only hit at the end of last year. We are still losing jobs at a very large rate. The rig count is plummeting and at the present time, there are really no front-end projects. If Brent stays at $15–16, I think that our best estimate is that the North Sea might, I repeat might, just begin to come up again in the first or second quarter next year.'

Many industry sources argued privately that the massive redundancies reflected a desire to reshape organisations and that the cull was more savage than justified by the decline in revenue. Furthermore, in sharp contrast to many papers presented at the last World Energy Council Congress, also held in Houston, many groups envisaged improvements in the way in which they operated, rather than a fundamental change of method.

One exception was Bob Peebler, President of Landmark Graphics Corporation. He emphasised that the 'huge force' of the new information technology gave an opportunity for players who were adept at operating in a new way, compared with those who resisted change. Many companies did not implement new technology sufficiently to achieve significant competitive advantages and failed to reorganise regularly. Functionally driven teams should be replaced by business driven teams, he said, and in the new era technology should be more business driven. The oil industry still wasted money: more was spent on drilling fluids for dry holes than on information technology. Frequently, it was too painful for oil groups to move up the 'curve of new technology', so they remained static.

More consolidation

Most speakers thought that alliances and mergers would continue because companies had to reorganise on a continuing basis. The arrival of new technology, even if oil prices are sustained, justifies change.

Peter Kinnear, Vice Chairman of the Petroleum Equipment Supply Association, quoting figures from Simmons & Co. International, said that the upstream sector merger and acquisition activity last year was worth $15bn and the total so far this year was $63bn. This reflected the need to lower cost structures. 'For the oilfield service and supply industry, the challenge put to us by our customers has been to provide seamless and reliable integrated packages of goods and services in the most cost-efficient way.' This had motivated much of the merger and acquisition activity, up from $4.9bn in 1995 to $23.3bn last year. 'I think we will continue to see more of this activity, especially between companies pairing up to enhance product lines, technology and experience.'

In less than two years, Schlumberger has reduced its workforce of 47,000 by 10,000 to save $600mn a year. The group is now organised into 25 'geomarkets' in four operating areas, not nine as before. Information and knowledge technology, 'the modern way to run businesses', is being used increasingly. Victor Grijalva, Vice Chairman of the group contended that it was not enough to cut the number of people, 'you have to cut the organisation'. 'We must focus now on integrated solutions. Efficiencies can be gained through shared resources. A lot of companies are going to use this method,' he said. There was still substantial excess capacity and more consolidation was required. Companies had to do things differently and should embrace, not fight, change. Groups that failed to use new technology and to undertake research and development would fail.

Planning ahead

Don Vaughn, Vice Chairman of Halliburton, maintained that, to manage a downturn, groups had to plan while enjoying an upturn. They also had to manage a balance sheet that was not over-leveraged. Companies must recognise that there really was a downturn. 'The downturn is very obvious now, but in the 1980s many debated its presence for a couple of years,' he commented. Dresser and Halliburton had agreed the merger in the upturn but it made more sense now and was a 'tremendous opportunity to take huge costs out. It gave us a running start as the markets declined,' he said.

Jim Day, Chairman of Noble Drilling, had seen only four good years since 1982. The number of employees in the oilfield service and equipment-manufacturing sector tumbled from 508,000 in 1982 to 195,000 last year. 'There needs to be more consolidation and people working together because our customers are becoming fewer and fewer. Unless you get size, you aren't going to be able to respond to the market and to do that through consolidation.' The combined market capitalisation of the largest oil companies was $921bn, while the oil service market is at $109bn. The offshore drilling contractors generate $22bn in market capitalisation. Despite the disparity in these figures, the risk had been passed to the supply sector and 1998 expenditure exceeded revenue by 108%. 'If this continues, pretty soon there may be only one drilling contractor,' he warned. He also indicated that there was a need to halve the number of leading offshore drilling companies to five.

Veritas, a medium-sized company of which Dave Robson is Group Chairman, reduced staff numbers from 4,500 to 2,500 in the last year. He recommended that small and medium-sized companies should prepare by controlling growth, avoid stock market exuberance and trust their instincts and common sense. Balance sheets should be kept as debt-free as possible. During a downturn, 'cash is king' as it allows companies to take advantage of opportunities and to acquire good people discarded by other groups. 'Nobody has special information now because of the speed of transmission so run the business on the assumption that a downturn could occur tomorrow.' Veritas had taken its operational people and made them into businessmen, he explained. Each was trained for 90 hours last year on, for example, how to read a balance sheet.

Hire-and-fire reputation

Schlumberger, Halliburton and Noble conceded that the industry was acquiring a hire-and-fire reputation but argued that the long-established groups would be better placed than new organisations to secure and retain young employees. As older personnel retired, promotional opportunities would be good and the technical challenges and good pay would attract new entrants.

Bobby Tudor, Managing Director of Goldman Sachs, believed that eventually there will be three or four huge international integrated oil companies. Another category, the 'regional integrated', would include groups such as Statoil and Petrobras. Independents will be divided into two main types, he predicted. There could be international independents, such as Anadarko Petroleum, while other niche independents would focus on basins and plays. The problems would occur for those independents 'between' these groups and thousands would vanish, he said. However, consolidation in the upstream sector would mean 'massive property sales all over the world coming out of these mergers...Independents will exploit and develop these properties much more aggressively. Apache, which is buying some Shell acreage in the Gulf of Mexico for $700mn, might have four rigs operating on the block, whereas Shell might have hired two.'

The market would reward groups involved in mega-mergers but would be less impressed with those smaller companies, such as Lasmo and Monument, which secured more modest savings through mergers and created less value. Tudor did not expect any more consolidation of the majors this year but indicated that there could be significant activity in the next tier.

Matt Simmons, President of Simmons & Co. International, said that 12 publicly traded offshore drillers was too many. Fewer would prop up day rates. A recent 15% decline in offshore rig utilisation prompted a fall of 70% in day rates. 'The jury was out' on whether recent upstream mergers, especially among the majors, would create a more efficient sector, he said. The most nimble upstream groups came from outside the ranks of the majors.

Juan Szabo, the PDVSA Vice President of Exploration and Production, was more critical of mega-mergers. 'Why do you expect to get a gazelle from the pairing of two dinosaurs?', he asked.

Awards and citations

BP Petroleum Development Limited won the Distinguished Achievement Award for companies for its development of the Foinaven and Schiehallion fields, west of Shetlands. The DeepStar (deepwater staged recovery) industry-wide programme, led by Texaco, received a special citation for its efforts to establish methods for developing large and small deepwater fields in a low oil price environment.

Finding a new drilling concept

A group of oil and gas industry representatives has been working over the past year to develop new drilling techniques and practices in a bid to cut costs. A 'finder well concept' has been developed in Phase 1 of the programme which is said to reduce the cost of drilling a well by up to 50% through sufficient planning. *John G Williams* of Conoco, and *Jean-Pierre Foehn* of TOTAL provide an overview of the programme's progress to date and outline future plans.

The Crine Network has estimated that it costs $13/b to take a recent average, low-volume UK Continental Shelf (UKCS) oil field through its entire lifecycle from acquisition to abandonment. Cambridge Energy Research Associates has validated this estimate with one of its own at $12.80/b. Clearly with the oil prices hovering at or below $13/b as they have done for the past several months, it has become extremely difficult for oil companies to fund continued exploration in the UKCS with this cost level. Oil prices will rise and stay up, costs must come down and stay down, or a combination of the two must occur to reduce the threat to future UKCS exploration.

Under the coordination of the Crine Network and the UKOOA Exploration Committee, a multidisciplined team comprising 18 people has been working on a project to reduce exploration wells costs for the past eight months and has developed the 'finder well' concept. A finder well is an exploration well that is drilled at minimum cost to meet the key objective of the well plan to determine the presence of hydrocarbons. Other names used to describe this concept are dip-stick, post-hole, and quick-drill.

Historical perspective

On 16 July 1998, representatives from several oil industry companies consisting of operators, non-operators, and contractors, met to discuss ways in which the cost of drilling wells in the UK could be lowered as future drilling projects were being threatened by the low oil price. A multi-disciplined team was formed and the name 'Double the Value of Wells by 2000' was given to the project.

The team is working under the leadership umbrellas of Crine and UKOOA. As the task facing the team involves many areas, it was decided to break the project into four parts and work them in sequence. The four phases are:

- Phase 1: Finder wells (completed)
- Phase 2: Development wells (to finish by 4Q1999)
- Phase 3: Alliances (to finish by 2Q2000)
- Phase 4: New technologies (to finish by 4Q2000)

Following finder well team meetings in 1998 and 1999 four main areas of cost savings were identified:

- Sufficient planning with no 'change orders' during drilling.
- 'Lessons learned' about best practices.
- Minimal formation evaluation.
- Challenging the well design.

Planning a finder well

Early planning of a finder well and staying within the guidelines of the plan once the well is being drilled are key to drilling a finder well within the reduced Authority for Expenditure (AFE) amount. This means that planning must begin early and that a full, multi-disciplined team must work together to fully define the key objectives of the well based on the critical uncertainties.

Often, changes are made to the well plan with little consideration to the overall cost of the well. In order to reduce well costs, plans must be made well in advance to find the lowest cost solution. After this is done, the well plan should be frozen in order to lessen costs. The cost of a well can be reduced by up to 50% by sufficient planning.

Best practices

Most team members shared one or more examples of a conventional well AFE compared to the same well drilled as a finder well AFE. Best practices learned by drilling were shared with the other team members so that industry as a whole could benefit. It is estimated that the cost of a well can be reduced

	Finder well	Conventional well
Total days	15.9	25.5
Strings of casing	2	3
Evaluation days	3	8
Core	No	Yes
DST (drill stem test)	No	Yes
Cost	$2.0mn	$3.1mn
% reduction	37	None

Table 1: An example of a 'best practice' finder well drilled in the northern North Sea compared with a conventional well drilled in the same area

by up to 15% by employing best practices. An example of a best practice is selecting casing points at the most cost effective formation depths that lead to reduced number of casing strings.

The example in **Table 1** shows a 'best practice' finder well drilled in the northern North Sea compared with a conventional well drilled in the same area. This example demonstrates a case of 37% cost savings by using the finder well concept. It is assumed that this well represents the best practice for the area in which it was drilled.

Minimal formation evaluation

Formation evaluation received the most debate among team members. Culturally, geoscientists and reservoir engineers have a long history of accumulating vast quantities of data while drilling exploration wells. Typical types of data obtained are multiple wire-line logging runs, cores, drill stem tests, logging while drilling, side wall cores, side-tracks, velocity surveys, vertical seismic profiles (VSPs), and many more. Each data type requires valuable rig-time to acquire.

The team estimates savings of up to 40% can be realised by minimising the amount of data collected during the drilling of a finder well, particularly when other associated costs are reduced as a result of less open-hole time. Remember that the key uncertainty of a finder well is determining the presence of hydrocarbons. A single logging-run over the objective interval is all that is required to learn the answer to this key uncertainty. Given the high risk of the typical finder well, around 75% of the time there will be no commercial hydrocarbons. For the successful finder wells, as with successful conventional wells, full data can be collected with the first appraisal well eliminating the need to mobilise expensive formation evaluation equipment for the finder well.

Obviously, each well is different and must involve the full team when planning the formation evaluation. Data collection should be supported by 'value of information', decision tree analysis, or decision and risk analysis. The operator and its partners are best able to decide what data are needed and what they can afford.

Challenging well design

Wells can be over-designed to reach their reservoir objective. If the aim is to save money while drilling, the well design can be challenged without compromising safety.

Currently, the team believes wells are designed to eliminate risk rather than manage risks. The value in challenging well design can be realised when casing strings can be eliminated or holes can be drilled using smaller diameter well bores. An operator and its partners have to accept that maybe one well in ten may fail to reach its objective. However, if the savings are high enough per well, an operator can re-drill one out of ten wells and still save money on the overall program. It is estimated that savings related to drilling with less conservative well designs could be as high as 25%.

Cutting costs

Each of the four areas of cost reduction is linked. For example, better planning might result in the utilisation of best practices. Challenging the well design might result in reducing the amount of data acquired. As such, the team feels that using the above four areas of cost reduction can yield a cumulative cost reduction for a multi-finder well programme of up to 30%. This can be achieved now using available technology. The only thing that is required is a cultural change away from the way we have always done things.

The main benefit of switching to the lower-cost finder well concept is the ability of operators and their partners to drill more exploration wells in the UKCS for the same amount of money. Put another way, operators could drill the same number of wells at a reduced cost. Either way, without the change, exploration is threatened in the face of historically low oil and gas prices.

Path forward

In coordination with the UK DTI and sponsorship of the Crine Network, the UKOOA Exploration Committee, and the Petroleum Exploration Society of Great Britain (PESGB), the team plans to host two workshops:

- DTI Conference Centre, London, at 13.00 on 7 June 1999
- University of Aberdeen in Meston Hall, Aberdeen, at 13.00 on 16 June 1999

The purpose of these workshops is to present the finder well concept to a broader audience and encourage debate among the industry and government.

Phases 2 and 4 of the 'Double the Value of Wells by 2000' project entitled 'Development Wells' and 'New Technologies', respectively, have begun. If you would like to be involved, contact Steve Brady, the team leader, on Tel: +44 (0)1224 205328.

Team players

The team members for Phase 1 of the 'Double the Value of Wells by 2000' project are:

Jean-Pierre Foehn – TOTAL (team lead)

John Williams –	Conoco
Steve Brady –	Conoco
Colin Oswald –	Elf
Steve Holehouse –	TOTAL
Peter Jackson –	Enterprise
Richard Smout –	Mobil
Ian Williamson –	GMIS-E
Bill Pitman –	KCA Drilling
Jim Rust –	Shell
David Owen –	Crine
Dave Taylor –	KCA Drilling
James Stockley –	CIECO
Gordon Law –	Enterprise
June Gemmell –	TOTAL
Mike Salter –	Abbot
Julian Roberts –	Baroid

Devaluation changes oil and gas investment climate

Nearly two years after its liberalisation Brazil's oil industry is facing a complex and uncertain future in the wake of January's 35% net devaluation of the real. The delicate political balances – which prised open the country's energy markets to private sector investment after an often painfully slow debate – are no longer predictable as the economy, already in recession before the devaluation, is forecast to contract by between 2% and 3% of GDP this year. *Maria Kielmas* reports.

The aftermath of the devaluation highlighted sharp divisions in the government and congress between those who believed inflation control should be set aside in favour of growth and those who advocated controlling inflation through a strong currency. Superficially, investor interest in the first exploration round, launched by the oil regulator Agência Nacional do Petróleo (ANP) just one week after the devaluation, remains firm.

However, low oil prices and a continuing polemic between the ANP and potential investors about the precise duration of exploration phases as well as future tax loads, has swayed companies into cutting back on investment plans. Shell has trimmed its planned spending over the next five years from $3bn to $1bn while Statoil has left the country.

Investment in the refining and marketing sector, as well as utilities such as gas and electricity, has to be reassessed in the light of the recession and an unpredictable real / dollar exchange rate. Even long-cherished dreams held by Argentina and Venezuela that Brazil would be a captive oil buyer are fracturing as Brazil seeks closer ties with Nigeria. Some local commentators believe that the devaluation has plunged the Mercado Comum do Sul (Mercosul, the common market grouping of Brazil, Argentina, Paraguay and Uruguay, also known as Mercosur (Mercado Com'n del Sur) in Spanish) into its worst crisis since its creation in 1991.

By March 1999 pessimism had given way to a qualified cheer with the revision of Brazil's November 1998 $41.5bn refinancing package with the IMF (International Monetary Fund) and the disbursement of a second loan payment of $4.9bn. The political isolation of Minas Gerais, State Governor and Former President Itamar Franco, whose moratorium on state debt payments to the federal government precipitated but did not cause the current crisis, added further cause for optimism.

Although the exchange rate stabilised at 1.73 reals to the US dollar in early April, the government is far from solving its crucial problem of controlling the federal fiscal deficit. This reached 8% of GDP ($64bn) at end-1998 on top of a current account deficit of 4% GDP.

Currency devaluation

The real risk of currency devaluation had already been evident in 1997 in the wake of the Asian financial crisis but this did not dent the confidence of international companies in the country's oil opening or in investing in the electricity and gas sectors.

The hope was that the re-election of President Fernando Henrique Cardoso would create enough political will to tackle the root cause of the fiscal problems – the social security system, the unwieldy civil service and the constitution. President Cardoso was respected as the author of the 1994 real plan that stabilised the currency and controlled inflation. But the power and independence of the congress and state governors, frequently exercised in favour of their local paymasters, means that controversial reforms can take three years or more to be approved, as was the case with the oil liberalisation bill.

Petrobrás problems

At end-September last year Petrobrás had a total debt of $9.88bn, of which $7.44bn was in foreign currency (mostly dollar denominated with $2.49bn denominated in reals). Roughly half of the debt had a maturity at under one year.

The company is also less than half as profitable as its private sector counterparts. In 1997 the average oil company return was 15.5% but Petrobrás registered just 7.3%. The same year YPF registered 13%, Exxon 18% and Eni 21%. For 1998 the company registered net profits of 1.43bn reals (when the exchange rate was 1.21 reals to the US dollar) on a turnover of 15.58bn reals. In 1997 net profits were 1.53bn reals on a turnover of 14.97bn reals.

The government has had plans since 1995 to sell 31.7% of Petrobrás preference shares. Currently, the state owns 84.4% of Petrobrás voting shares and 52.88% of the company's total capital. A change in the company's statutes means that foreigners may now buy voting shares, previously restricted to Brazilian nationals only. The initial plan was to issue ADRs on the New York Stock Exchange (NYSE). But this has been delayed by ten huge jobs required to clean up Petrobrás balance sheets to comply with NYSE disclosure rules.

The likelihood now is that the stock could be sold in one batch to an outside investor while some of the company's five subsidiaries could also be sold off. The government has ruled out a complete privatisation of Petrobrás and its fuel distributor subsidiary BR Distribudora. But this could just be timely semantics. Nevertheless, foreign exploration subsidiary, Braspetro, is definitely on the sales block. In January this year Petrobrás produced a total of 1.159mn b/d of crude of which 51,539 b/d came from Braspetro's overseas operations. Gas production was 33.3mn cm/d (1,168mn cf/d) of which Braspetro produced 2.27mn cm/d (79.56mn cf/d).

Company changes

The government's view was that in order to bring Petrobrás under government control, sort out its finances and prepare it for competition with the private sector, it needs to be run by someone with a thorough knowledge of private business, some knowledge of government but not necessarily, as it transpired, with any oil industry experience.

Petrobrás' President over the last six years, Joel Rennó, resigned in January, appointing in his place as Interim

President the company's Transportation Director, Admiral Leite Pereira.

In an informal interview after his resignation, Rennó admitted that he has always been opposed to the oil reform that stripped Petrobr·s of its monopoly and is against the company's privatisation. Rennó has been a highly respected professional in Latin America's state sector oil industries. But this ideology clashed with economic reforms underway. Rennó's days in his post were already numbered with the appointment of David Zylbersztajn, formerly the São Paulo State Energy Secretary and President Cardoso's son-in-law, as the head of the oil regulator, ANP.

While Zylbersztajn cut his teeth on liberalising the São Paulo state gas sector in preparation for the import of Bolivia gas through the newly constructed Bolivia–Brazil gas pipeline, Rennó was responsible for the delays to this pipeline project, firstly in his opposition to the expansion of gas development and later through his determination to ensure that Petrobrás controlled the nascent gas industry.

President Cardoso wanted his close ally and former Communications Minister Luiz Carlos Mendonça do Barros to take over as head of Petrobrás. Although news of his imminent appointment was welcomed in the financial markets as a sign that the government would finally modernise Petrobrás, it was stalled by his political past. Mendonça do Barros was forced to resign from his post last year amid allegations that he and other associates tried to influence the $19bn privatisation of state telecom company Telebrás.

Energy Minister Tourinho has been appointed as the Chairman of the Petrobrás Board of Directors while the President and effective CEO is Henri Philippe Reichstul, a French-born and Brazilian naturalised economist and lately private banker who served as an adviser to Planning Minister João Sayad in the 1980s during the presidency of José Sarney.

Fields on offer

It was BNDES President Borges who first revealed that the company's new strategy would be to dispose of marginal, uneconomic fields, in the same way as YPF in Argentina had done nearly a decade ago. The first such fields to be offered to private investors are located in the northeast of the country, mainly in the Recôncavo Basin, a poor area where the government hopes the oil opening will generate 60,000 new jobs. Although the ANP's industry presentations of the first exploration round in January received a good turn out from companies, the government has had to scale down its ambitions for total new exploration investment.

At end-February it had signed just 12 exploration contracts out of 32 memoranda of understanding which had been concluded separately prior to the round. These 12 contracts will bring in just $563.3mn of new investment instead of a hoped for $5bn, now scaled down to $1.2bn. Fiscal provisions in the Brazilian contract are fourfold: rental fees, royalties of between 5% and 10%, a signature bonus and a sliding scale Norwegian-type special participation feed which, according to the government, adds an average extra $0.45/b in tax on production of 100,000 b/d in 500 metres of water.

But industry critics of the exploration terms have focused largely on the three-year exploration phase. In its January presentations, ANP argued that this could be extended twice each for a further two years. But companies note that model contracts to date stipulate that the exploration phase can only be extended in the case of gas development which has to wait for an infrastructure to be installed. Despite ANP's comments to the contrary during its presentations, companies such as Shell continue to lobby for an extension to the exploration period which it deems necessary in very deep water or in unexplored distant rainforest.

Devaluation has made oil industry costs inside Brazil cheaper for foreign investors. This could act as an encouragement for companies to use local contractors for services from field supplies to platform construction. On average the local content of oil field developments in Brazil has been only 10 to 20%.

Privatisation programme

But the first real test of the new economic order governing Brazil's oil and gas industry will follow the scheduled privatisation of the São Paulo state gas company Companhia de Gãs de São Paulo (Comgás) in April. A consortium of Shell, British Gas and local group VBC Energia (which itself comprises Votoratim, Bradesco and Camargo Corrêa) won the bidding for Comgás. They offered 1,652,579,00 reals ($989.6mn), a price 119% above the base price.

British Gas will be the majority shareholder in the consortium, holding 64%, and will act as technical operator. Shell, which already held 19.86% of Comgás, will increase its stake to 26%. The remaining 10% will go to VBC Energía. This local consortium controls the São Paulo electricity utility Companhía Paulista de Força e Luz (CPFL).

The new concession is for a 30-year term, renewable for a further 20 years. The distribution grid is to be expanded by 400 km, incorporating a further 200,000 consumers, and gas tariffs are set for an initial five-year period. While the catchment area has a population of 28mn, there are only 300,000 gas consumers at present. The new owners plan to invest $200mn in the project over the next two years.

Impact of low oil prices

Brazil's neighbours are already feeling the wider impact of both lower oil prices and devaluation. In the first two months of 1998 Argentina exported $41mn of crude to Brazil. This fell to $16.4mn during the same period this year. Argentine oil companies have always felt they had an export advantage in Brazil's captive market. Venezuela began to feel the same, hoping that it could export its Orimulsion to substitute as fuel oil for old electricity generating plant in Brazil. But already by mid-1997 Nigeria had supplanted Argentina as the main oil supplier to Brazil because it was quicker to adjust its prices than Argentina, Venezuela or even Saudi Arabia. By end-1998 Nigeria was supplying 120,000 b/d to the Brazilian market followed by Argentina's 110,000 b/d. Venezuela is expected to drop far down the league because of its Opec commitments to cut production.

Brazil imports about 850,000 b/d of crude oil and refined products. Oil business between Brazil and Nigeria may increase through complementary ventures in exploration and even imports of Nigerian LNG to the northeast Brazilian market where Shell, the operator of the Nigerian LNG project, has plans to use it as a gas source for power generation. Brazil hopes to increase energy commerce with Nigeria following the early-April visit of Nigeria's President Oludsegun Obasanjo to Brazil. But Brazil's Mercosul partners are watching developments with trepidation as their plans for greater economic and political integration, including a single currency in the region, appear to erode.

Brazil's decision to embark on unilateral import tariff negotiations with the Andean Community (formerly the Andeaŋ Pact) prompted the other Mercosul partners to accuse the government of wanting to break up the Southern Cone market. The Brazilian government has denied this. For the international oil industry the overall investment climate remains encouraging though unpredictable, but world oil prices are the smallest (relatively) of problems to address.

Is oil really a strategic commodity?

Our US correspondent *Peter Adam* reports on a recent think-tank debate in Washington DC in which participants questioned whether today's US policies regarding Middle East security and oil imports are outmoded.

Winston Churchill understood the strategic importance of oil. On the eve of World War I, as First Lord of the Admiralty, he engineered the British fleet's switch from coal to petroleum-based fuel. As Lord Curzon noted: 'The Allied cause [in WWI] floated to victory on a sea of oil.'

Churchill, always the political realist, did not allow a strong aversion to socialism to preclude him from directing the British Government's purchase of Anglo-Persian Oil – later to become BP – which at that time (1914) possessed petroleum concessions in Iran. And ever since, ensuring access to petroleum from the Arabian Gulf has been a cornerstone of British and US policy.

Of think and tracked tanks

Today, according to the Washington DC based think-tank known as the Cato Institute, such policies are outmoded. Cato estimates that the bill the US pays for securing access to Middle East petroleum is \$50bn/y, \$100 for each barrel America imports from the Arabian Gulf, and argues that this money is wasted because oil has negligible geostrategic value.

On 15 April at a panel discussion in Cato's F A Hayek Auditorium, well attended by Washington's energy cognoscenti, Jerry Taylor, the Institute's Director of Natural Resource Studies, with support from William Niskanen, its President, debated petroleum's strategic value with Robert Copaken, Senior Middle East Energy Analyst with the US Department of Energy's (DOE's) Office of International Affairs.

So what? and what's so

Oil, Taylor stated, should not unduly concern US policy makers because there is plenty of it and substitutes are readily available. In his words: 'Opec nations are profit maximisers and no amount of foreign policy grovelling has ever been able to change that fact... Oil embargoes are economically meaningless... There is not, and never was, an oil supply "crisis"... A vast array of unconventional fossil fuel sources become economically viable once oil prices exceed about \$20/b... Opec's ability to affect the market today is overstated.' He continued: 'And even were oil the strategic commodity that many allege, it does not satisfactorily suggest an answer to the next question; (sic) so what?'

Taylor then proceeded to question the conventional rationale for forcing the Iraqi army out of Kuwait in 1991: that it was necessary to prevent Saddam Hussein from dominating the Arabian Gulf and thus gaining control of the world's most ample oil supplies. Citing economist David Henderson, he stated that: 'had Iraq captured Saudi Arabia, Oman, Bahrain, Yemen, and the United Arab Emirates, it would have controlled only about 20% of world oil production. If we use standard US Justice Department calculations regarding mergers and market power, we find that Saddam's new found market power could have resulted in oil prices rising to about \$25/b. That's hardly a crisis.'

Not everyone agrees. As John Lichtblau, Chairman of the Petroleum Industry Research Foundation Inc (PIRINC), who reviewed the text of Taylor's remarks, pointed out: 'Production levels per se are not germane here. If Saddam Hussein were to dominate the Persian Gulf countries he would control nearly 50% of world petroleum exports, and two-thirds of proven reserves (according to the *BP Statistical Review of World Energy*). Iraq would also control about 80% of readily available spare producing capacity. Ten years from now all these percentages will be substantially higher, according to most forecasts. Thus Lichtblau pointed out, there is a strategic risk to commercial Middle East oil supplies.

He also challenged the \$50bn figure often used as the price the US pays to ensure access to Arabian Gulf oil. He explained that the US military expenditures in the region are not a function of the US's fluctuating Middle East import levels. A disruption of Middle East oil exports affects prices globally, regardless of US import dependence. Furthermore, most of the military personnel and equipment the US currently deploys in the Middle East would remain in US armed forces, and their costs reflected in the US military budget, even if the US were to withdraw from the Middle East.

Perplexing realpolitik

Taking a leaf from Lichtblau's book, Dr Copaken, a DOE official with extensive experience with the perplexing

continued on p40...

Foreign majors bolster Mozambican gas potential

The end of the civil war in Mozambique, the recent change in attitude of the government towards an investor-friendly foreign investment climate, and recent success in economic growth with 12.7% achieved in 1997 and double-digit growth in 1998, have provided a sound footing for the development of the country's recently discovered and commercially exploitable gas reserves, reports *Priscilla Ross*.

Atlantic Richfield Corporation (Arco) – which is currently being taken over by BP Amoco in a $26.8bn deal – is one of the major players in the Mozambique arena. Together with partners, South African oil company Sasol and Zarara (United Arab Emirates), it was due to release reserve numbers as *Petroleum Review* went to press.

An Arco spokesman told *Petroleum Review* that: 'Mozambique has high potential as a low cost gas producer and the company and its joint venture partners are currently in negotiations for gas sales agreements.' He declined to quantify the reserve potential of any of the fields under investigation but 'significant' and 'world-class' were the descriptive terms used.

BP is already involved in Mozambique – but in an oil play rather than gas. Exploration in the Zambezi licence area is at an early stage with seismic being shot in February last year.

Adding momentum to the Mozambique gas play was the recent confirmation by US gas major Enron that negotiations between the company and the government of Mozambique are underway. The discussions include the exploitation and development of the Pande field located near Mambone in Mozambique. These talks will also determine the construction of a 378-mile pipeline to the Maputo Iron Project. The spokesman for Enron said that the 'negotiations are going well' and explained that the gas project alone would cost $400mn. No figures were given on the capital cost of the pipeline.

Mozambican Prime Minister, Pascoal Mocumbi, announced recently that the new negotiations are aimed at creating a framework agreement to replace the heads of agreement signed in November 1995 with Enron. The 1995 agreement expired in May 1998 and it is now understood that the government has given Enron mineral and drilling rights over an extended area of Inhambane, building on what was originally covered in the 1995 agreement.

It was initially planned that the iron direct reduction component of the Maputo Steel Project would use the majority of the proven reserves from the Pande field over the 25-year project lifetime. Enron was hopeful at that stage, that additional discoveries would lead to incremental gas sales in Maputo, the Mozambique capital, and also to the South African gas market.

New developments

Mozambique is on the brink of the commercial exploitation of natural gas reserves that will support several major new industrial projects such as the Beira Hot-bricketted Iron (HBI) project, Billiton's recently financed Mozal aluminium smelter and the Maputo Iron project. It is also understood that discussions with major potential industrial users in South Africa are at an advanced stage.

Looking specifically at the gas fields, Arco (47.62%), Sasol Petroleum International (47.62%) and Zarara (4.76%) jointly own three fields – Temane, Sofala and M-10. Sasol (50%) and Arco (50%) also have a joint venture on the Mazenga field.

A five-well drilling programme on the Temane field has been completed – gas was discovered in all the wells. According to Arco the drilling programme has 'confirmed field size and reserves, and the results have exceeded expectations.' The spokesman cautioned: 'Until we find a gas market we will wait,' but also indicated that Arco was trying to finalise sales agreements.

The preferred market for Temane gas is South Africa because it contains enough gas to provide 10% of the country's energy needs. Temane is situated in Inhambane, the southern province.

Of the three fields jointly owned by Arco, only Temane has been drilled so far. As a result, there is a greater degree of confidence on reserves for this field. Sofala and M-10 are exploration targets and still being evaluated but, with the 2D seismic that has been shot offshore, correlation has been found with the wells onshore and the region is reported as being 'quite prospective'. Sofala, is located a few kilometres from Beira and therefore is ideally situated for the Beira HBI Project. The M-10 field is slightly southeast of Beira and could potentially supply gas to Beira, the free trade zone around it and central Mozambique. The gas could also flow south to South Africa if there was sufficient demand.

Mozambique also has good hydro-

Field/licence	Ownership to rights	Reserves
Buzi-Divinhe	Zarara-Scimitar Hydrocarbons	33bn cm
Inhaminga	Scimitar	Not yet known
Mazenga	Sasol Petroleum International, Arco	Not yet known
M-10	Sasol (47.62%), Arco (47.62%), Zarara (4.76%)	Still under evaluation
Pande	Enron	Heads of agreement renegotiation
Rovuma Basin	Lonrho (50%), Mozambique gov. ENH (50%)	Not yet known
Sofala	Sasol (47.62%), Arco (47.62%), Zarara (4.76%)	Seismic
Temane	Sasol (47.62%), Arco (47.62%), Zarara (4.76%)	Five wells drilled
Zambezi	BP	Seismic

Oil and gas fields, and licences, in Mozambique

electric power and South Africa could export power from its coal-fired power stations. However, gas looks as though it can compete exclusively at the Beira Iron Project as gas is an important part of the chemical process in producing HBI. Indeed, the Beira project could well be the anchor client for Sofala gas which is located within a few kilometres of Beira. JCI (previously Johannesburg Consolidated Investments) has suggested that over the life of the Beira HBI project, around 0.75tn cf of gas would be consumed over 20 years.

Petroleum Review asked the Arco spokesman if Mozambique was strategic to the company's future. He said: 'It is difficult in today's low oil price environment, but this is a growing regional market and there will be gas production in the long run. Whether it will be attractive for Arco depends on how quickly markets develop.'

He also said that JCI is not committed yet to the Beira project but 'once committed, Arco will complement JCI'. The question now is whether BP Amoco will be as committed to the development of gas in Mozambique following its takeover of Arco.

The road ahead

The cost of bringing in an exploration rig to Mozambique is now several million dollars, although the Arco spokesman said 'rig rates are currently a third of what they were a year ago'. The cost of drilling essentially has three features: mobilisation, day rate and equipment, and consumables usage. Mobilisation is the least flexible whereas the other two components are more susceptible to changes in the oil price.

The end of the civil war in Mozambique, the change in attitude of the government towards an investor-friendly foreign investment climate, and recent success in economic growth with 12.7% achieved in 1997 and double-digit growth in 1998 provides a sound footing for the development of the recently discovered commercially exploitable gas reserves.

Enron looks set to go ahead on Pande but the development of Temane, Sofala and M-10 fields could be debated in the London boardroom of BP Amoco post the Arco merger.

...continued from p38

realpolitik of petroleum, presented a more measured, conventional assessment of how the Middle East and its oil figure into US policy.

He took issue with Taylor's contention that oil has readily available substitutes. Citing a *Cost/Benefit Assessment of Oil Imports Report* produced by the DOE, he pointed out that substituting away from oil is more difficult than in the case of most other minerals. Furthermore, he noted that importing nations are vulnerable to serious adjustment problems when faced with oil supply or price shocks. He also stated that oil and its revenues have come to figure in the production of weapons of mass destruction, such as those Saddam Hussein has been attempting to build – a development that Taylor failed to address, but one that enhances oil's strategic value.

Furthermore, Dr Copaken noted that: '[oil] isn't that cheap or easy to explore for, drill, find and develop, refine and transport, and distribute and market... as both producers and international oil companies will be quick to tell you. Unless, that is, you have already invested years (decades) of capital technology, labour and skilled manpower to "prove up" the billions of barrels of reserves that we often tend to take for granted until its not available.'

Events subsequent to the panel discussion rendered some of Taylor's rhetorical thrusts ill timed, if not wide of the mark. Despite his contention that Opec's control over oil prices is more limited than many think, in the week following the Cato Institute discussion, oil extended the price appreciation it has enjoyed since the beginning of the year, exceeding $18/b in the US – an increase of over 70% since last December. Most analysts attribute this run-up primarily to cutbacks engineered by producers including Opec members, notably Saudi Arabia which has reversed crude course and reduced production to below 8mn b/d. Time alone will tell whether exporters have the potential will to stay the course and not overproduce. However, recent signs of recovery in Far Eastern countries have raised the spectre of increasing global oil demand, the disappearance of spare production capacity worldwide, and further price appreciation and increased international, if not US, dependence on oil from the Arabian Gulf – at some point in the indeterminate future.

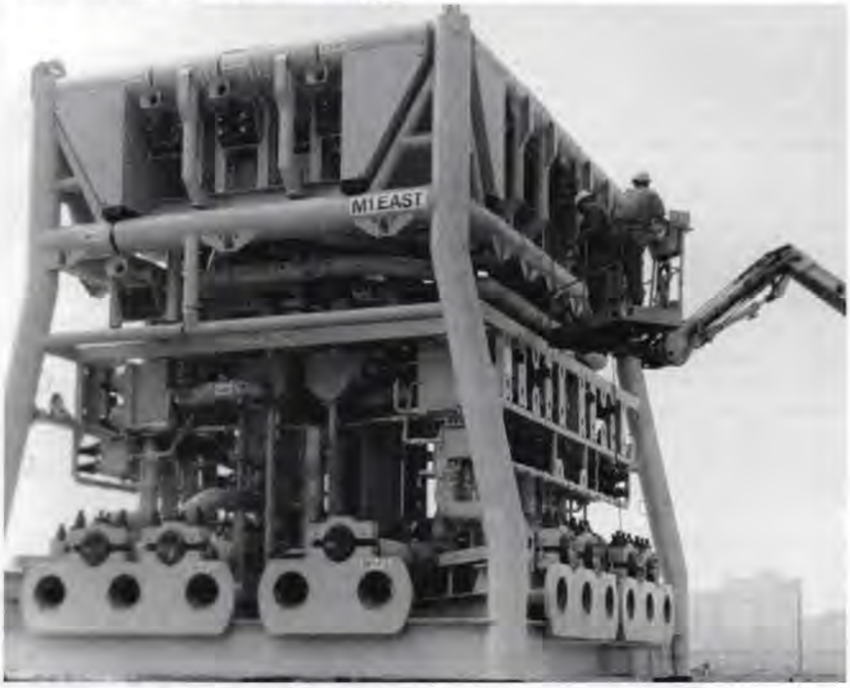
Politics and petrol

Despite what think-tank ideologists may think and say, politicians, who must live day to day in the messiness of the real world, realise that oil is too important to be left to the markets, or the policy 'experts'. This was brought home clearly to recent occupants of the Oval Office. Stagflation caused by mismanagement of the US economy, compounded by soaring oil prices and the humiliation of the hostage situation in Iran, contributed to the resounding defeat President Jimmy Carter suffered at the hands of Ronald Reagan. Also, US (and world) dependence on Arabian Gulf oil was the primary factor that prompted President George Bush to organise an allied force to drive the Iraqi army out of Kuwait.

And, as Churchill would no doubt have appreciated, petroleum is proving critical in the current conflict in the Balkans, which is ironically where World War I started. Nato members are attempting to embargo petroleum imports into Serbia as their air forces destroy the country's petroleum refining and distribution infrastructure. A more vivid demonstration of the strategic importance of oil is hard to imagine.

The author would like to thank Dr Mary Barcella, a respected economist and consultant to the US DOE, for her editorial comments, but takes complete responsibility for the article's text.

Subsea technology award



Fuel Subsea Engineering, a division of Smit Land & Marine Engineering, has won the Pipeline Industries Guild 1999 award for the most significant contribution to subsea pipeline technology. The company received the award for its diverless maintained cluster system (DMaC System) which has been utilised on BP Amoco's West of Shetland developments. Diverless subsea connections for flowlines and umbilicals are necessary on virtually every piece of major subsea equipment and the DMaC connection system has fulfilled this operation, states the Guild.

The system is based on modularised equipment, designed to offer the operator maximum flexibility in choice of field layout, choice of equipment/service providers and choice in the field installation/construction sequence with the benefit of phased production during installation and drilling, explains Fuel Subsea Engineering.

System improvements are ongoing in a bid to further enhance the cost effectiveness of the DMaC installation and to extend the technology to other applications. Since first being used on the Foinaven project in 1995, system modifications are reported to have produced ROV tooling improvements in the design of mechanical equipment, advances in sealing technology and improved operating procedures. The current version of DMaC system has completed 88 pipeline and 44 umbilical subsea connections in the 1998 season on BP Amoco's Schiehallion field.

Tel: +44 (0)1483 795300
Fax: +44 (0)1483 795315

New window on the geophysical world

Petroleum industry geological consultancy Cambrian GeoSolutions has unveiled what it claims is the first-ever computer graphic metafile (CGM) publisher for geoscientist users of Windows-based computers.

Developed to meet the consultancy's own electronic reporting and publishing needs, the Wotan software allows users of Microsoft Windows (95, 98 and NT) to properly access the CGM images generated by all other geological and geophysical applications, whether they are Unix or Windows generated. All types of data can be viewed and printed, ranging from simple maps and well logs, through complex seismic displays and sophisticated montages.

Wotan offers a range of flexible viewing and selection options and incorporates zoom, pan and rotation features. It can be run on a wide range of desktop and portable computers.

Tel: +44 (0)1291 673022
Fax: +44 (0)1291 673023

Easypay at the pump

Shell Nederland has launched a nationwide forecourt fuel payment system called 'Easypay' which allows motorists to fill up with fuel as normal but not have to go into the shop to pay. Customers place a special microchip keyring near an electronic reader built into the pump and enter a personal identification number to facilitate the automatic debiting of their bank account.

Easypay has been introduced at 100 outlets in the Netherlands and more are to follow. Shell says it may introduce the system in other European and non-European countries as well. The payment at the pump concept has already proved popular in the US.

Philips Semiconductors developed and supplied the MIFARE® technology for Easypay. Both Philips and Shell say that they expect the system to 'be the payment method of the future', and have signed agreements which allow the oil company to use the technology globally. Philips also supplies the chips and card readers in the pump.

Shell Nederland
Tel: +33 10 469 6200
Fax: +33 10 469 6201

Bench-top measurement

Philip Harris Scientific has launched a new range of bench-top Denver Electrochemical Instruments designed to accurately measure one or more electrochemical parameters depending upon the model used.

The Model 250 for example (pictured) provides research grade pH, conductivity and ion measurements with a few simple keystrokes, while the Model 225 offers a combination of research grade pH and ion selective analysis. Users of the latter model may set up their own methods or adapt those which are pre-programmed.

Tel: +44 (0)1543 480077
Fax: +44 (0)1543 480068

High performance digital compass module

Honeywell Control Systems has introduced the HMR3000 Digital Compass Module – an electronic compass designed to provide fast response time and excellent resolution. The device uses solid state magnetic sensors and a two-axis tilt sensor to provide accurate heading plus pitch and roll readings. The compass is said to be easy to use, offers a rugged design calibrated for hard iron compensation, and is said to be reliable even when tilted up to 40°.

The HMR3000 is claimed to have a response time to 20 Hertz and a high heading accuracy of 0.5° with a resolution of 0.1°. Heading output (roll, pitch, yaw) is provided in National Maritime Equipment Association format with an RS232 or RS485 electrical interface.

The compass is available as a circuit board weighing less than 56 grammes or in a non-magnetic 8.26 x 2.54 x 2.23 cm aluminium enclosure. CE certified units in an aluminium enclosure are also available.

Tel: +44 (0)1344 656000
Fax: +44 (0)1344 656015

Mini-sample flashpoint tester

Petrotest Instruments has unveiled the lastest model of its PMA-4 Pensky-Martens automatic flashpoint tester with miniature cups which require only 2 to 15 ml of liquid sample material. The miniature cups replace the standard 70 ml cups for reproduceable flashpoint tests according to ISO 2719/4.2. For official tests, the cups can be swapped over so that the standard size can be used instead – there is no need for a second test machine, says the company.

The basic kit includes three cup/lid assemblies, allowing three samples per test to be prepared in one step. Each cup has its own lid with stirrer and temperature sensor. The excess cups are cooled until the first test is done. Then the old cup is simply exchanged by a new one which becomes connected to the test machine by twisting the multi-function pivot head. Test parameters can be called up as a whole from an integrated database, so that few manual inputs are required for most tests.

Tel: +49 23 03 81 975
Fax: +49 23 03 86 676

New tough alloy tackles offshore applications

A new range of ToughMet copper–nickel–tin spinodal bronze alloys has been developed for the offshore market by Brush Wellman. The new alloys offer minimal seawater corrosion rates, exceptional strength and resistance to fatigue failure, and natural anti-fouling and anti-galling properties, making them ideal for downhole drilling tools, production and completion tools as well as subsea and wellhead products, states the manufacturer.

The ToughMet range is also claimed to be resistant to corrosion in sour environments and to combine high strength, good ductility and a low coefficient of friction. According to the company, the alloys are capable of withstanding ten times the loading of C96500 aluminium bronze, making them suitable for applications where long bearing/wear life is required.

The alloy structure is continuous cast by a patented EquaCast process. Rod, bar, tube and billet can also be supplied with continuous casting in complex shapes which saves both material costs and machining time, says the company.

Tel: +44 (0)118 930 3733
Fax: +44 (0)118 930 3635

Autosampling fuels

A new, high capacity autosampler capable of handling a range of aqueous and viscous liquids including all types of fuels and lubricants is now available from Sartec.

The AIM2000 incorporates an X-Y autosampler and a dispenser/diluter syringe to provide flexibility and a high throughput in a single run. The probe arm can be adjusted for height to allow test tubes up to 300 mm in height to be used. The standard unit can handle up to 270 samples, which can be increased to 540 with the addition of a moveable extension rack.

The unit has a small footprint and is claimed to maintain sample integrity through the probe design and efficient wash system.

Windows-based software allows the configuration of tray layouts, methods and runs in a simple intuitive manner, states the company. The AIM2000 can operate as a stand-alone sample preparation system or can be controlled by external software via the unit's serial communications ports, allowing the sample to be fed directly to an analyser.

Tel: +44 (0)1732 780600
Fax: +44 (0)1732 885541

Seismic analysis

Landmark Graphics Corporation has added PostStack ESP™ (Event Similarity Prediction) interpretation software to its integrated PostStack™ technology suite for poststack seismic data optimisation, seismic attribute extraction and similarity processing. Designed to replace the company's Continuity Cube software, PostStack EPS is an improved productivity tool for interpreters working in highly faulted areas to unravel complex faulting patterns. It can also detect subtle stratigraphic features such as reefs and channels on seismic data.

Tel: +1 281 560 1555
Fax: +1 281 560 1586

Monitoring valves via the Internet

The new Field Browser™ system from Neles Controls is designed to monitor smart field instruments for operation status and performance changes from any computer with an intranet or Internet connection.

An online intranet/Internet connection to valves, as well as instrument products, systematically detects status changes and sends priority warnings to plant personnel via web page, e-mail or mobile phone before processes are disturbed. Typical errors include a valve not following a predetermined control signal or failure of a positioner to operate.

The system monitors each field instrument connected to it via a Hart® Multiplexer network. It collects messages and converts them to an HTML document that can be accessed from anywhere in the world, explains the manufacturer. The collected information is stored in a database which serves as an information bank that can be used to evaluate and develop a current or his-

torical perspective on an individual valve's performance.

For a more in-depth insight into the nature of a problem, the valve can be accessed and remote diagnostics performed through any computer linked to the user's intranet using the manufacturer's Valve Manager® software.

Tel: +1 508 852 3567
Fax: +1 508 852 8762

New energy-efficient, enviro-friendly engine unveiled

Australian company Smart Energy Solutions recently unveiled an energy-efficient, alternative fuel Plasma Turbine Engine.

Unlike conventional internal combustion engines used in vehicles, this new engine is based on an isothermal Carnot cycle. According to the manufacturer, the 'beauty of the engine is in its simplicity'. It has one spark plug which sparks only once when starting the engine. This produces rotary motion, spinning at a constant speed of 12,000 rpm but with a variable power output which is ideal for generating electricity.

Unlike conventional internal combustion engines which are around 35% thermal-efficient, the Plasma Turbine Engine is claimed to offer a 75% thermal efficiency. In addition, the engine is said to be capable of handling any combustible liquid or gas as fuel. The manufacturer also points out that, as the fuel is burned at the same temperature in all parts of the chamber, there are virtually no nitrous oxide emissions produced.

'Because the engine can be used to generate electricity, it replaces the need for a stand-by generator, or grid connection.' explains Chief Executive Officer Stephen Riddell. 'Better still, it is cheaper and cleaner than most grid electricity, and you are not paying for the electricity lost during transmission from the power station. It is very quiet, can be built in a range of sizes to meet all needs and can even be used, by trapping the heat from exhaust gases, to produce hot water for household or commercial consumption. This means it is suitable for cogeneration applications as well. When used this way, its thermal efficiency approaches 95%.'

The engine has only two moving parts per chamber, making it inexpensive to maintain, states the company. The expected life span is 25 years, similar to a normal motor.

Tel: +612 9959 1024

Cuttings flow meter

Geoservices has developed a new instrument that quantifies the volume, and thus flow, of rock cuttings exiting a well while drilling. The Cuttings Flow Meter was developed in response to a need for more information on hole cleaning efficiency, especially when drilling highly-deviated, extended reach or deepsea wells.

Continuous, real-time information on hole-cleaning efficiency enables the drilling and mud parameters to be adjusted for optimum cuttings removal and reduces the risk of stuck pipe, explains the company.

Tel: +33 1 48 14 84 05
Fax: +33 1 48 65 63 83

New maintenance service

Basildon, Essex-based supplier of fire and gas detection equipment Allison Engineering has launched a special maintenance contract for the calibration of such equipment in the UK.

The company's new calibration and maintenance service division offers a customised solution from full test, calibration, repair and reporting on a weekly basis, to annual service visits.

Tel: +44 (0)1268 526161
Fax: +44 (0)1268 533144

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

Decommissioning the Brent Spar*

Tony Rice and Paula Owen (E & FN Spon, an imprint of Routledge, 11 New Fetter Lane, London EC4P 4EE, UK). ISBN 0 419 24090 (paperback); ISBN 0 219 24080 (hardback). 182 pages. Price: £14.99 (paperback); £45 (hardback).

This book aims to provide a balanced, impartial account of the decommissioning of Shell Expro's Brent Spar oil storage buoy. It includes coverage of Greenpeace's activities in protest against the dumping of the Spar in the deep waters of the Atlantic; Shell's activities and reports concerning its planned decommissioning programme; the UK government's input as well as that from the EU and OSPAR; and media coverage. The publication shows the failings in the dialogue process and highlights the need to approach decommissioning decisions in a different way in the future.

World Oil & Gas Companies Financial Yearbook 1999

(Available from Noble Financial Publishing, 76 George Street, Edinburgh EH2 3BU, Scotland). The yearbook and CD-Rom are available at an introductory price of £320 ($520) and £480 ($780), respectively, for a limited period. A combined book/CD package is also available at the introductory price of £500 ($999).

This directory provides background information and contact details for over 300 companies involved in the international oil and gas industry. It also analyses the financial performance of over 200 of these companies and tracks pan-sector trends. All figures are converted to US dollars to allow instant cross-sector comparisons. The directory is also available on a CD-Rom which also includes reports on oil and gas producing countries, new stories related to this sector dating from 1979 and full company annual reports and accounts.

Confined Space Entry: A Guide to Compliance

Frank R Spellman (Technomic Publishing Company, 851 New Holland Avenue, Box 3535, Lancaster, PA 17604, USA). ISBN 1 56676 704 0. 134 pages. Price: $54.95.

This book brings together the US Occupational Safety and Health Administration's (OSHA) regulatory requirements for making safe and proper confined space entries. It provides clear sample programmes to serve as models when the reader wishes to write his/her own confined space entry procedures. Topics covered include: the OSHA standard; evaluating the workplace; permit-required confined space entry; permit system; training; assessment of on-site personnel; confined space rescue; alternative protection measures; procedures for atmospheric testing; and respiratory protection.

National Oil Companies of South East Asia

Gurdip Singh (FT Energy, Maple House, 149 Tottenham Court Road, London W1P 9LL, UK). ISBN 1 84083 093 X. 122 pages. Price: £395 ($632).

The economic crisis in South East Asia has brought about a major political change in the region, forcing the Indonesian President and the Thai Prime Minister to step down during 1998, alongside widespread allegations of corruption in political and economic circles. Ambitious plans for new projects have been shelved and inward investment has dwindled. This report provides detailed analysis of the structure and direction of South East Asia's national oil companies in the light of these recent developments, and outlines expected future trends.

Emissions International

(Distributed by the Institute of Petroleum. Available from Portland Press Ltd, Commerce Way, Whitehall Industrial Estate, Colchester CO2 8HP, UK). ISSN 1466 0202. Four issues per annum. Price: £495 (50% discount available for NGOs, academics and government departments).

This quarterly publication provides an overview of the latest news and views on the developing greenhouse gas emissions market. It includes analysis of the Clean Development Mechanism and Joint Implementation projects and includes regular contributions from leading decision-makers and key industry players. The magazine also focuses on the design and implementation issues of the proposed CO_2 emissions market, and assesses the legal implications and strategies for businesses. Those who subscribe now will receive a free fortnightly news update via e-mail.

* *Available on loan from the IP Library*

Latest from the Library

Library redevelopment – reminder

The IP Library at 61 New Cavendish Street will be CLOSED for a major upgrading and refurbishment from 6 July, for approximately six weeks. Although you will be unable to visit our facilities, you will still be able to contact us by post, telephone, fax and e-mail. We hope to reopen on 16 August.

Library shelving

The existing library shelving will be available for sale following the refurbishment. Anyone interested in purchasing it should contact Catherine Cosgrove.

Recent additions to library stock

- *Worldwide Refining and Gas Processing Directory*. 55th Edition. Pennwell Directories, Houston, Texas, US, 1999.
- *Africa – Middle East Petroleum Directory*. 15th Edition. Pennwell Directories, Houston, Texas, US, 1999.
- *SI 1999 No 160 Petroleum: The Petroleum (Current Model Clauses) Order 1999*. ISBN 011080418X. Stationery Office, 1999.

Free energy information on the Internet

The Information for Energy Group (IFEG) has organised an afternoon seminar for 30 June 1999 on this subject. See the advert on p29 of *Petroleum Review*, or contact Sue Tse for more information.

Contact details

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

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

MOVES People

Robert J Angel has been named Chairman and Chief Executive Officer of Caltex Corporation, the refining and marketing joint venture between Texaco and Chevron. Effective from 1 July, he will replace **David J Law-Smith**, who will take early retirement. In 1986 Angel became Chairman and Managing Director of Mobil Oil South Africa and oversaw the sale of the business to Gencor in 1989, after which he stayed on as Chief Executive Officer and Managing Director for what ultimately became Engen Ltd, the South Africa-based integrated oil company. Caltex Senior Vice President **Jock McKenzie** has also been named Chief Operating Officer.

TOTAL's President of Exploration and Production **Daniel Valot** has left the company to join the Technip Group. As a result, **Christophe de Margerie** has been appointed President of the Exploration and Production Division, a new division created from the merger of the Exploration and Production and Middle East divisions. He is also the company's new Vice President. With effect from 1 July, **Michel Benezit** will become Executive Vice President of the new division and will be replaced in his role as Vice President TOTAL Overseas by **Dennis Poole**. Later in the year **Patrick Rambaud** will become Senior Vice President Middle East. He will be replaced in his previous role of Vice President Trading and Shipping by **Patrick de La Chevardiere**.

Jack E Little, President and Chief Executive Officer of Shell Oil Company, is to retire at the end of June. He will be succeeded by **Steven L Miller**, who will also become Chairman of the Shell Oil Company Board of Directors, succeeding **Mark Moody-Stuart**. As a result, Miller is to resign from his positions as Managing Director of Royal Dutch Petroleum Company and Royal Dutch/Shell Group Managing Director. However, he will continue his involvement with the Group's Committee of Managing Directors on matters relating to succession planning and global strategy development. Also, **Walter van de Vijver** is Shell Exploration and Production's new President and Chief Executive. Van de Vijver was previously President and Chief Operating Officer of the company. In his new role he will be responsible for the Royal Dutch/Shell Global EP Executive Committee.

Norrie Stanley, BP Amoco Vice President, has been elected Chairman of Russian oil company Sidanco, of which the oil group has a 10% stake.

Petrobrás has announced that **Jose Carlos Countinho**, previously Vice President of the Braspetro subsidiary, will head its new exploration and production Board. The company's new downstream Board will be headed by **Albano de Souza Goncalves** whose previous position was as chief of the transport area.

Tony Ward has retired from his position as Production Director of Amerada Hess after 12 years in charge of the company's operations in Aberdeen. Ward is a Fellow of the Institute of Petroleum. Former Operations Director **Nick Fairbrother** has taken over the position, responsible for operations in Aberdeen as well as developments in London.

President and Chief Executive Officer of Global Marine, **Robert E Rose**, has been named Chairman of the Board. He succeeds **C Russell Luigs**, who remains a Director and has been named Chairman of the Board's Executive Committee. **James L McCulloch** has been promoted from his position of Vice President and General Counsel to Senior Vice President and General Counsel.

John N Seitz has been elected to the position of President and Chief Operating Officer of Anadarko Petroleum Company. He is currently serving as the company's Executive Vice President–Exploration and Production.

The International Energy Agency has elected Belgian **Fernand Sonck** as its new Chairman until 31 August 2000, when he will be succeeded by **Ambassador Arne Walther** of Norway. Since 1980, Sonck has been the Belgian representative to the High Level Energy Group of the European Union Council, and the Belgian representative to the Governing Board of the IEA.

Intertanko has appointed **Westye Høegh** as its new Chairman. He takes over from **Richard du Moulin**, whose three-year term of office has been completed. Høegh is Chairman of Leif Høegh & Co and was President of the Norwegian Shipowners Association from 1994 to 1995. **Ran Hettena**, Overseas Shipholding Group, and **K H Koo**, Tai Chong Cheang Steamship Co, have both been elected as Vice Chairman. First International Group of Companies' **Paul Slater**, Marinvest's **Lars Mossber**, and Mitsui OSK Lines' **Hirohiko Tanaka** have been elected to the Intertanko Executive Committee.

Norwegian state-owned company Statoil has named **Ole Lund,** Chairman of the Oslo stock exchange, as its new Chairman, replacing **Kjell Kran**.

Chris Fay, former Chairman and Chief Executive of Shell UK, has become Chairman of the Government's Advisory Committee on Business and the Environment. Fay is Deputy Chairman of Stena International, Non-Executive Director of BAA, Anglo American and Stena Drilling. He is also a Fellow of the Institute of Petroleum.

Membership News

NEW MEMBERS

Mr D J Adams, Bonner & Moore Associates GmbH
Mr A Adetosoje, Vectra Oil (Nigeria) Limited
Mr H A Al-Sultan, Arab Petroleum Training Institute
Mr D A Atkinson, Deutag Drilling
Mr D Atkinson, DHL Worldwide Express
Dr R Baltenas, Lithuania
Mr R Bhagwandin, Guyana Oil Company
Mr R J R Blomqvist, Watford Petroleum Limited
Mr A G Booth, Simmons & Simmons
Mr C Brewster, IBE Fire Safety Management
Mr P Brohm, BP Oil UK Limited
Mr I J Bruce, Booy Industrial Services (L) Ltd
Mr C R Cross, BWD Rensburg
Mr A P Crowle, Maidenhead
Mr J Eonne, Sonara, c/o Citac Limited
Mr P M Evans, Pipetronix Limited
Mr R A Evason, Downstream Environmental
Mrs J A Farrow, W Gilchrist & Company
Mr G Frimpong, Dexon AZ Limited
Mr A H S Harris, Malton
Mr S Henderson, London
Ms S Hoffman, McKinsey & Company
Mr G B Holiday, Buckingham
Mr T Imtiaz, Aberdeen
Mr S J Johnson, Hartlepool
Mr J Joynson, Performance Improvements (PI) Limited
Mr I J Kaye, Wigan
Miss A M R Kenna, London
Mr A Kerrison, Technical & Mechancial Services (Brighton) Limited
Mr M Ketabchi, London
Mr A Leddy, Maud
Dr G Livingstone, Dounby
Mr D J Lye, Barry
Mr A Malhotra, Slough
Mr D Marriott, Chaltham
Mr B Martin, Drum Engineering Company Limited
Mr J-P McGinley, Netherlands
Mrs C McLoughlin, Bloomberg
Mr B R Moses, Engen Petroleum (UK) Limited
Mr H M D S Mosquito, M'bakassy & Filhos, Luanda
Mr E M Narrirov, State Oil Company of Azerbaijan
Mr S Oike, NKK Europe Limited
Mr D M Raitt, The Netherlands
Mr J Ronni, Musor Oy
Mr R W Rowntree, Meridian Business Projects Limited
Mr A Samousev, JSC Nord Oil
Mr D A Seymour, Rhossili Engineering Limited
Mr J Shiach, Alfa Laval Oilfields Limited
Mr J Shirodkar, Hawkpoint Partners
Mr H J Simons, M W Kellogg Limited
Mr H S Smith, Glasgow
Mr W J Smith, Eadie Holdings plc
Miss E Soutou, London
Mr R L Stassen, IRM Services BV
Mr R J Tarry, Bisley
Mr S J Turner, The Netherlands
Mr J Walsh, Staines
Mr A L West, Evoco Services
Mr R F J White, Chester
Mr A Williams, Lloyds Register
Mr S J Wright, Aberdeen

NEW STUDENTS

Mr A A Al-Attar, Kuwait
Mr R A M Al-Mieni, Centre for Petroleum Studies
Ms W M H Al-Wardy, London
Mr M Arif, Oxford
Ms E Da Silva, London
Mr U Ezgu, London
Mr R Odokki, Canada
Ms H Taylor, Institute of Security Studies
Ms T Tomoye, University of Dundee

NEW CORPORATES

NUPI SpA, Via Colombarotto, 58 Imola (BO), Italy
Tel: +39 542 624911 Fax: +39 542 624900
e-mail: info@nupinet.com

Representative: Mr M Genoni, Managing Director
NUPI SpA manufactures plastic pipes and fittings for the conveyance of crude, gas and chemicals in the oil industry both upstream and downstream. It operates four production plants in northern Italy and has offices based both in Italy and abroad. NUPI is an ISO9002 certified company.

Steptech Instrument Services, Steptech House, Maxwell Road, Stevenage, Herts SG1 2EW, UK
Tel: +44 (0)1438 312425 Fax: +44 (0)1438 312111

Representative: Mr J Arnold, Business Development Manager
Steptech Instrument Services supplies continuous oil-in-water monitors. The monitors are known for their reliability and have a very low cost of ownership, typically requiring two hours of maintenance every six months, dependent on application. Users include major oil companies, both offshore and onshore; power stations; chemical plants and petrochemical sites.

Rotork Controls Ltd, Brassmill Lane, Bath, North Somerset BA1 3JQ, UK
Tel: +44 (0)1225 733200 Fax: +44 (0)1225 333647

Representative: Mr Peter Cox, Project Engineer
Rotork Controls Limited is an established supplier of heavy duty electrical, hydraulic and pneumatic valve actuators to the oil, gas, power, water and mining industries. Rotork has offices and manufacturing plants worldwide.

TDG Nexus, Trunk Road, South Bank, Cleveland TS6 6UL, UK
Tel: +44 (0)1642 452552 Fax: +44 (0)1642 452955

Representative: Mr C Galbraith, NE Engineer
TDG Nexus is involved in road tanker transport.

Adler & Allan Ltd, 22/42 Livingstone Road, Stratford, London E15 2LJ, UK
Tel: +44 (0)181 555 7111 Fax: +44 (0)181 519 3090

Representative: Mr M Calvert, Managing Director
Adler & Allan Limited is involved in fuel oil distribution; oil spillage clearance; tank cleaning, removal, repair and installation. It also deals in oil/water/petrol uplifts, transfers, disposal risk assessment, testing and remediation. Adler & Allan provides a total solution to oil and petrol users/producers with regard to tanks and products.

ERF Ltd, Sun Works, Middlewich Road, Sandbach, Cheshire CW11 3DN, UK
Tel: +44 (0)1270 763223 Fax: +44 (0)1270 766068

Representative: Mr M Rowley, Director
ERF Limited manufactures and sells heavy commercial vehicles. It is also involved in the sale of parts and servicing.

IP Conferences and Exhibitions

Workshop on

The Control of Legionnaires' Disease in the Oil Industry

London: 10 June 1999

Legionnaires' Disease bacteria may occur whenever water is held between 20°C and 50°C and the presence of organic materials will further increase the risk of their proliferation. Humans coming into contact with such water run the risk of contracting Legionnaires' Disease.

In order to assist in the control of this disease, the Institute of Petroleum has arranged a one-day Workshop that will address aspects of *Legionella* infections with particular reference to the oil industry.

Presentations will be made on clinical aspects of the disease; detection, risk assessment and control of Legionnaires' Disease bacteria; HSG 70 and legal implications of *Legionella* outbreaks. In addition, there will be specific case studies from the oil industry. To augment these presentations, there will be an exhibition with invited water treatment companies demonstrating their techniques of controlling the disease.

Who should attend?

- Oil company Health and Safety officers
- Operators of retail sites
- Water treatment companies
- Local authority health officers
- Microbiologists and Occupational hygienists

The programme and registration form is now available

International Conference on

Gas to Liquids

London: 6 October 1999

There has been much publicity about the development of gas to liquids technology in the last 2–3 years. This International Conference will take a serious and critical look at the subject – assessing its viability from the point of view of technology, economics, environmental desirability and effectiveness as a vehicle for the use of 'stranded' gas.

The programme and registration form will be available in July

International Conference and Exhibition on

Offshore Marine Support (OMS '99)

Southampton: 12–13 October 1999

A joint IP/ABR Company Conference

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

Exhibition

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

The programme and registration form is now available

Workshop on

Health Effects of Fatigue on Performance

London: 21 October 1999

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

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

Autumn Lunch

Guest of Honour and Speaker: Dick Cheney

Chief Executive Officer, Halliburton Company and Former US Secretary of Defense 1989–1993

Savoy Hotel, London: 15 November 1999

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

The Ticket Application Form is now available.

Tickets are limited so book early to avoid disappointment

International Conference on

Developments in Measurement and Loss Control in Oil Refineries

London: 7–8 December 1999

Training Courses

The Institute of Petroleum is organising a portfolio of nine energy related training courses. Further information is available from Jane Hill, at the IP.

Tel: +44 (0)171 467 7105, Fax : +44 (0)171 255 1472

e-mail: **jhill@petroleum.co.uk**

Programmes and registration forms for all events are available from:

Pauline Ashby, Conference Administrator, at the Institute of Petroleum

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

e-mail: pashby@petroleum.co.uk

or view the IP website:

www.petroleum.co.uk

EVENTS Forthcoming

JUNE

7 **London**
Cost-Effective Exploration Wells
Details: PESGB
Tel: +44 (0)171 495 6800
Fax: +44 (0)171 495 7808
e-mail: pesgb@pesgb.demon.co.uk

7–9 **Moscow**
ISOPE Euroms-99: International Pipeline Symposium
Details: ISOPE
Tel: +1 303 420 8114
Fax: +1 303 420 3760

8–9 **Leipzig**
Central European Gas Conference
Details: EconoMatters
Tel: +44 (0)171 650 1430
Fax: +44 (0)171 650 1431
e-mail: confs@economatters.com

8–9 **Brussels**
Euro Financing for the European Energy Sector
Details: The Energy Exchange
Tel: +44 (0)1242 529090
Fax: +44 (0)1242 529060
e-mail: wra@enexltd.infotrade.co.uk

10 June
London: *Workshop on the Control of Legionnaires' Disease in the Oil Industry*
Details: Pauline Ashby, The Institute of Petroleum

13–17 **Stavanger**
The Pipeline Pigging Conference
Details: Pipes and Pipelines International
Tel: +44 (0)1494 675139
Fax: +44 (0)1494 670155

14–15 **Dubai**
Investing in Middle East and North African Petroleum Industries
Details: IBC Gulf Conferences
Tel: +971 4 362992
Fax: +971 4 360116
e-mail: ibcgulf@emirates.net.ae

14–15 **London**
Implementing the Kyoto Protocol
Details: Georgia Wright, The Royal Institute of International Affairs
Tel: +44 (0)171 957 5700
Fax: +44 (0)171 957 5710

14–16 **Antwerp**
European Refining Technology Conference – Computing
Details: Global Technology Forum
Tel: +44 (0)1737 365100
Fax: +44 (0)1737 365101
e-mail: events@gtforum.com

14–16 **London**
Nigeria Energy Summit
Details: Penny Richards, IBC Global Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e-mail: cust.serv@ibcuk.co.uk

15–17 **Gloucestershire, UK**
Forum for Fire Hazard Management and Fire-Fighting in the Oil, Gas and Chemical Industries
Details: Publishing & Exhibition Services
Tel: +44 (0)1622 850312
Fax: +44 (0)1622 8503009

15–18 **Curaçao**
Bulk Liquid Measurement
Details: Abacus International
Tel: +44 (0)1245 328340
Fax: +44 (0)1245 323429

16–17 **Estonia**
Baltic Energy
Details: SMi
Tel: +44 (0)171 252 2222
Fax: +44 (0)171 252 2272

16–18 June
London: *Course on Introduction to Oil Industry Operations*
Details: Pauline Ashby, The Institute of Petroleum

17–18 **Sicily**
European Oil Refining Conference and Exhibition
Details: Edward Bradfield, WEFA
Tel: +44 (0)171 631 0757
Fax: +44 (0)171 631 0754
e-mail: Edward_Bradfield@wefaltd.win-uk.net

18–21 **Woking, Surrey**
The Mechanics and Operations of Oil Trading
Details: The Petroleum Economist
Tel: +44 (0)171 831 5588
Fax: +44 (0)171 831 4567

21–22 **London**
Third Millennium Petroleum
Details: Sandra Shore, Global Pacific & Partners
Tel: +44 (0)1372 745959
Fax: +44 (0)1372 747947

21–22 **London**
1st European Petrochemicals Technology Conference
Details: Colin Chapman, Euro Petroleum Consultants
Tel: +44 (0)1483 771061
Fax: +44 (0)1483 756932
e-mail: 113120.1635@compuserve.com

21–22 **London**
Negotiating African E&P Licences
Details: EuroForum
Tel: +44 (0)171 878 6888
Fax: +44 (0)171 878 6885

21–23 June
London: *Course on Introduction to Petroleum Economics*
Details: Pauline Ashby, The Institute of Petroleum

23 **London**
Republic of Somaliland: Petroleum Exploration Opportunities
Details: Global Pacific & Partners
Tel: +1 281 597 5978
Fax: +1 281 597 9589
e-mail: GLOPACAMER@aol.com

23–24 **London**
PetroSET 99: Transferring Solutions to Impact the Oil and Gas Industry
Details: Jane Kennedy, CMPT
Tel: +44 (0)1870 6083440
Fax: +44 (0)870 6083480
e-mail: j.kennedy@cmpt.com

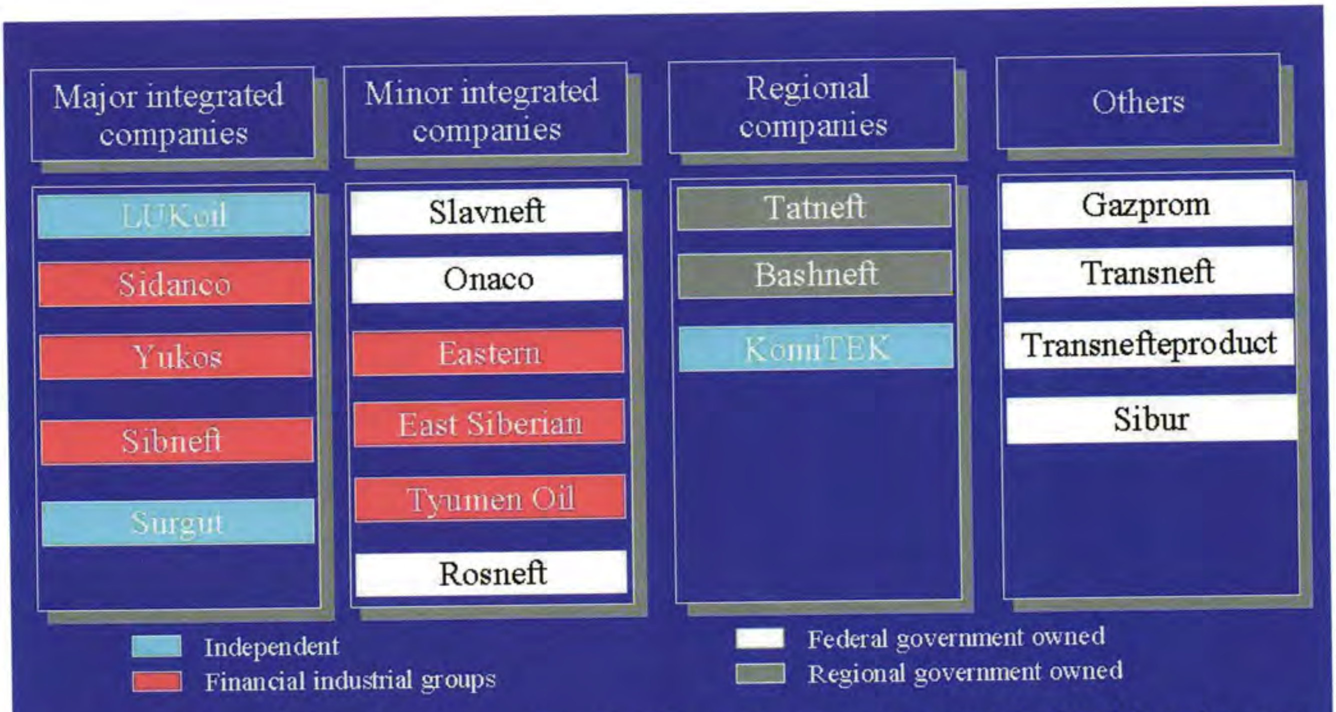
23–25 **Basal, Switzerland**
LIMS 99
Details: Jay Conference Services
Tel: +44 (0)1702 231268
e-mail: JayConferenceServices@compuserve.com

24–25 **London**
M & A and Restructuring in Global Oil and Gas: Strategies for Survival
Details: Penny Richards, IBC Global Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e-mail: cust.serv@ibcuk.co.uk

24–25 **London**
Worldwide Deepwater Technologies
Details: Penny Richards, IBC Global Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e-mail: cust.serv@ibcuk.co.uk

28–30 **London**
Sixth International Derivatives Conference
Details: The Futures and Options Association
Tel: +44 (0)171 426 7250
Fax: +44 (0)171 426 7251

29–30 **London**
The Essentials of UK Gas Trading
Details: IIR Ltd
Tel: +44 (0)171 915 5055
Fax: +44 (0)171 915 5056
e-mail: registration@iir-conferences.com



In our April issue (p15), the diagram (Fig 4) which accompanied the article titled 'A not so rosy outlook for Russian oil and gas' was incorrectly colour coded. The corrected version is printed above.