Petroleum review

MARCH 2004

IP Week 2004

- Inge Hansen: Sustainable oil and gas development
- Brian Hamilton: Focusing on the future
- Event highlights

Seismic

- Industry puts its faith in the reservoir

Africa

- Marginal field initiative raises political tensions

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

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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: Left: Land vibroseis units
Photo: WesternGeco

Right: Full house at the Grosvenor House Hotel for the 90th IP Week Annual Dinner. For full IP Week round-up see p27–35 *Photo: Jim Four*

contents

news

3 UPSTREAM
7 INDUSTRY
9 DOWNSTREAM

special features

12 EXPLORATION – SEISMIC
Seismic industry puts its faith in the reservoir
40 WEST AFRICA – ANGOLA
African focus for drilling company
42 AFRICA – NIGER DELTA
Marginal field initiative raises political tensions

IP Week 2004

27 IP WEEK – ANNUAL LUNCH
Sustainable oil and gas development
30 IP WEEK – ANNUAL DINNER
Focusing on the future
33 IP WEEK – ROUND-UP
Highlights from day one

features

15 ENERGY INSTITUTE – IP AWARDS
Prize-winning personality
16 GAS – GAS-TO-POWER
Balancing supply with politics
20 COMPANIES – EXPLORATION
New thinking needed for exploration
22 E&P – FALKLAND ISLANDS
Interest stirs in the frontier's frontier
23 COMPANY PROFILE – ENERGY AFRICA
Balancing a portfolio of low- and high-risk assets
24 EXPLORATION – HYDRATES
Small production heralds big future
36 BUSINESS MANAGEMENT – IT
Mobilising the oil and gas industry

regulars

2 FROM THE EDITOR/E-WORLD
48 LETTERS

ROUNDUP From the Editor

Riyadh – do we have a problem?

IP Week was once again a tremendous success, with over 2,500 executives taking part in some or all of the events. Reports of the lunch and dinner speeches are to be found on p28 and p30, while a coverage of the week's conferences appears on p33.

Every IP Week has its own tone and character, and this one was no exception. This time the underlying tone was slightly nervous, a sentiment that was never quite stated but was somehow there. Maybe it was the aftermath of the Shell reserves revisions, maybe it was the lack of new projects being discussed.

Over the last week or so BP has announced the go-ahead for the long-anticipated Greater Plutonio project offshore Angola, while Shell has announced the Jackpine oilsands project in Canada, and Iran has awarded a contract for the development of the southern portion of the Azadegan field – but all these were too late to be features of the week. The most likely explanation is that the future of Saudi production has suddenly emerged as a concern.

Matt Simmons, the Houston-based Energy Banker, has over recent months and in the opening speech of this year's IP Week raised the questions most in the industry would rather not think about. Can Saudi actually expand production in the way the EIA and the IEA require for their 'business as usual' scenarios? Can Saudi maintain production close to current levels? Worse still, following the chillier relationship with Washington, why should Saudi invest to increase production? Is there any chance that Saudi Arabia will open up to western investment?

Simmons concluded his speech with the question that nagged away at all who heard it: 'What is the prudent sustainable capacity for Saudi Arabia?'

In the course of IP Week a senior Aramco figure and a London-based analyst sought to assure listeners that Saudi production could, and would be, expanded – but the more people heard, the more uncertain they became. In the course of the week we learned that 90% of Saudi production comes from just eight mature fields; that all development wells in the Kingdom are now horizontal wells reaching up to 23,000 ft (nearly 7 km) across the fields; that around 1,000 of the country's 1,560 producing wells are horizontal wells with around 200 additional horizontal producing wells being drilled each year. To many this sounded like a country that was working hard to maintain production rather than one where you simply opened the tap wider when you wanted more production. But if the well managed and well funded Saudi oil industry is experiencing challenges, where does that leave the other Middle East producers?

This was not the only surprise IP Week brought. On the Monday a speaker from the generator Powergen, with brutal frankness, explained that the value of alternative electricity generated by windmills etc accounted for only 25% of the benefit to the generator, the other 75% being its value in meeting various government requirements. In short, renewables are wholly dependent on government regulation and investment in renewables is only possible if the government can assure investors that it will continue this effective subsidy. But, the cost to government will increase as the percentage of renewable energy rises.

The IEA in its latest *World Energy Investment Outlook* estimates the oil sector will need to invest over \$3tn, or \$103bn/y, to meet requirements over the period to 2030. Matt Simmons suggested such investments would only be possible at significantly higher oil and gas prices.

On p20 we reproduce Wood Mackenzie's recent *Insight* publication, which made the provocotive suggestion that company's are currently destroying value by exploration. This circle could be squared – but only at higher oil and gas prices.

That President Putin is a powerful and authoritarian figure is not in doubt. His sacking of his entire cabinet ahead of the election that he is virtually certain to win raises many doubts and concerns – not least about the future treatment of oil companies operating in Russia.

Just plain wrong

In last month's Editorial I quite erroneously suggested that non-Opec production peaked in 1998. It did not, but continued its steady expansion. My apologies (see Letters to the Editor on p48).

Chris Skrebowski

The opinions expressed here are entirely those of the Editor and do not necessarily reflect the view of the EI.

e world

The UK DTI has published its response to two consultations on proposals that are reported to radically reform EU competition law. These reforms, which will mean changes to the UK's competition laws, place national competition authorities and courts in the driving seat for the bulk of competition law enforcement and give them a stronger role in ensuring that markets across Europe work fairly. Details can be found at **www.dti.gov.uk/ccp/consultations.htm**

xRenewable energy could reap significant economic and social benefits for the UK, according to a recently published report. The Renewables Supply Chain Gap Analysis report assesses the current status of the renewables industry in the UK and its future potential for employment and the renewable energy industry. The study is now available from the UK DTI website at **www.dti.gov.uk/energy/renewables/renewables_uk/publications.shtml**

Briggs Environmental Services, the pollution-control specialist, and Aberdeen-based Cresent report that their web-based oil spill response training programme has proved so effective that it is now being used by every oil company in the UK sector. In addition to receiving information on the various types of pollution, their effects on the environment, the equipment available, methods for calculating the size of a spill and techniques for containment and clean-up, trainees are presented with a series of realistic scenarios involving small on-board pollution, and large-scale oil slicks. Trainees are assessed by their response to 'virtual' spills. On board a computer-generated oil-installation, they are able to place emergency 'spill kits' in locations of their choosing, select equipment depending on the type of spill, and take special precautions, such as preventing chemicals from reaching drains. In the larger-scale scenarios, an oil slick threatens the computer-generated coastline, which includes a town, wildlife reserve, a nudist colony and other sensitive areas. Trainees must calculate the size of the spill, judge where it's likely to drift, what type of pollution it contains, and when to alert the emergency services.

SPE has announced the launch of the SPE 'E&P Consultants Directory', a searchable database of consultants in the upstream oil and gas industry. This free online service – available at **www.spe.org/consultant** – puts users in contact with individuals or companies who can meet their specific consulting needs.

In Brief

UK

Paladin Resources has signed contracts with GlobalSantaFe Drilling UK for the provision of two mobile drilling units to work in the Montrose and Arbroath field area of the UK sector of the central North Sea.

Falkland Island Holdings (FIH) has, together with its joint venture partners Cambridge Mineral Resources and Global Petroleum, obtained financing from funds managed by RAB Capital to form a new Falkland Islands-based company – Falklands Minerals – through which it will fund further investigations of the minerals potential of the Falkland Islands.

Centrica has bought a set of North Sea oil and gas assets from ChevronTexaco for a total consideration, including the value of associated tax allowances, of £60.7mn ($109.2mn). Centrica is taking a 33.33% interest in the UK side of the Statfjørd oil and gas field, which is split between UK and Norwegian waters, and a 50% stake in the Orwell gas field in the southern North Sea.

Europe

The Mikkel gas development operated by Statoil has been officially inaugurated after being brought onstream at NKr1.8bn, more than 30% below its original cost estimate. The subsea field is tied back to the Åsgard B gas production platform. Recoverable reserves are put at 28bn cm of gas and 40mn barrels of condensate.

Talisman Energy has been awarded two new exploration licences in the Norwegian North Sea. The two licences contain part of blocks 2/1, 7/8 and 7/11 and were awarded to Talisman (60%, operator) and its co-venturer DONG (40%).

Norsk Hydro has entered into an agreement to sell to Statoil for an undisclosed sum its 10% stake in production licences PL064, PL077, PL078, PL097, PL099, PL100 and PL110 in the Norwegian offshore sector, including the Snøhvit gas field development. In a separate deal, Norsk Hydro is acquiring from Statoil its 2% interest in the PL134B and PL199 licences on Haltenbanken, including the Kristin field.

Talisman Energy has acquired from ConocoPhillips its 35% interest in licences PL143BS and PL143CS in block

NEWS Upstream

Downward revisions for Sable project reserves

In another sign that Canadian natural gas production may fail to live up to its promise, especially regarding its ability to supply a US market with production issues of its own, the operators of the Sable offshore project in Eastern Canada have made another in a series of downward revisions to estimated reserves.

The Sable Offshore Energy Project, located off the coast of Nova Scotia, currently represents 3% of Canada's total output of natural gas, but has been plagued by more than its share of production difficulties. Shell Canada, 31.3% owner in the project, made its third negative reserve revision in less than three years to the project in early February, while Pengrowth Energy Trust, an 8.4% partner, made revisions of its own, roughly in line with Shell's.

Other partners in the project – estimated when production began in December 1999 to contain 3tn of recoverable reserves – are ExxonMobil (50.8%), Imperial Oil (9%) and privately owned Mosbacher Operating (0.5%).

The field's problems may have implications down the road for the extremely tight natural gas market in New England. A report by the US Federal Energy Regulatory Commission in December 2003 noted that load factors on gas pipelines feeding New England are likely to exceed 90% for three months in 2004 and that existing Canadian imports to the region can only provide adequate supplies through 2005. The report determined that a combination of LNG and increased production from sources such as the Sable project will have to make up for additional regional demand beyond that point.

Shell's revisions to Sable's reserves have totalled 690bn cf so far, with consecutive downward revisions of 27% in 2001, 11% in 2002 and, most recently, 40%. This amounts to a cumulative revision of just over 60%. The latest revision stems from the fact that the partners have decided not to pursue production at one of what was originally seen as the most promising blocks in Tier 2 of the project – Glenelg – due to a high percentage of water produced.

Contract awards for Greater Plutonio

Sonangol, Angola's state owned oil company, has authorised BP to proceed with the awarding of major contracts for the development of Greater Plutonio. The project to develop six fields will be the first development in Angola's block 18 and the first BP-operated project in Angola. The fields Galio, Cromio, Paladio, Plutonio, Cobalto and Platina, collectively known as Greater Plutonio, are located in water depths of 1,200 to 1,500 metres. Development will consist of a single spread-moored floating, production, storage and offloading (FPSO) vessel linked by risers to a network of subsea flowlines, manifolds and wells.

Following authorisation to proceed, BP has awarded two of the major contracts for the development. The contract for engineering, procurement, construction and management (EPCM) went to Kellogg Brown & Root, while that for fabrication of the FPSO hull and topside equipment was awarded to Hyundai Heavy Industries. The vessel will be built in the Ulsan shipyard, Korea.

BG acquires El Paso's Canadian operations

BG Group is to acquire El Paso Oil and Gas Canada from El Paso Corporation for $345.6mn. El Paso Canada holds some 690,000 net acres, of which 630,000 is undeveloped oil and gas acreage that BG believes holds considerable exploration potential. The acreage is located in four core areas in the Western Canadian Sedimentary Basin, mostly in southern and western Alberta and northeastern British Columbia.

The acquisition also includes producing assets, which, at 31 December 2003, had gross working interest production of some 80mn cfe/d.

According to an independent evaluation by Ryder Scott, effective 31 December 2003, the properties concerned contain 132bn cfe of proved reserves, before royalties, of which some 84% is natural gas. The attractiveness of the properties also lies in their low operating costs and their proximity to existing infrastructure.

NWS Venture signs final gas deal

North West Shelf Australia LNG has signed a sale and purchase agreement for the supply of 0.6mn t/y of LNG to Chubu Electric Power Company, starting 2009. The deal represents the last of the sale and purchase agreements with the NWS Venture's customers that have underpinned the expansion of the Venture's LNG processing facilities at its gas plant near Karratha, Western Australia.

The NWS Venture is currently building a fourth LNG processing train with a capacity of 4.2mn t/y of LNG, significantly increasing overall capacity from the existing 7.5mn t/y. A second offshore trunkline is also being constructed, enhancing operational reliability and providing opportunities for growth. Meanwhile, a ninth LNG ship, due for delivery in April 2004, will add capacity to the Venture's shipping fleet of eight purpose-built LNG ships.

The North West Shelf Venture is also to install new technology worth more than A$32mn as part of a strategy to reduce air emissions – including oxides of nitrogen (NO_X), benzene, toluene and xylene (BTX), greenhouse gases and hydrocarbons – from the Karratha gas plant. The programme is expected to reduce NO_X emissions by 25% and BTX by up to 75%. It will lead to a greenhouse gas emission reduction of 350,000 t/y from the facility.

Iran puts out 16 blocks to tender

The National Iranian Oil Company (NIOC) has defined 16 new exploratory oil blocks in different parts of the country to be put out to international tenders in phases. The 16 blocks have been chosen based on consumption needs and proximity to oil processing facilities. Contracts will be issued on a buy-back basis.

The blocks to go on tender are Moghan I and II, Kouh-Dasht, Khorran-Abad, Kermanshah, Bijar, East and West Mokran, Zabol, East Jazmourian, Saravan, Tabas, Garmsar, Saveh, Raz, and Tapeh Marouh.

Indications are that 32 companies, both domestic and international, have voiced a readiness to submit bids in the pre-qualification stage.

In a reversal of past practice, and in order to improve the attractiveness of the contracts, NIOC will be able to sign the exploration, description and development phases of each block as parts of the same contract. According to the company, the exploration phase of each contract (to include an oil well and seismic surveys) will cost the contractor between $30mn and $40mn.

Blocks in four oil rich provinces in southern Iran – Khuzestan, Bushehr, Kohkilouyeh, and Llam, along with those in the Persian Gulf waterway have been excluded from the current tendering.

T&T licensing bid

Repsol-YPF reports that it is taking part in the tender offer put forward by the Government of Trinidad & Tobago on the exploration of two offshore blocks in the islands' waters. Winning the concession would increase Repsol-YPF hydrocarbon production in the country beyond the current figure of over 120,000 boe/d. The company currently has net proven reserves in the region of 879mn boe and forecasts that production will increase at a rate of a 44%/y in the period 2002–2007.

In 2005, following the start-up of the fourth LNG train approved by the Trinidad & Tobago Government, the gas contracted by Repsol-YPF Group in the country will reach 7bn cm – equivalent to more than 35% of Spanish annual consumption – almost the whole of which will be marketed in the US and the Caribbean. At present, Repsol-YPF sells 5bn cm/y of LNG to these markets.

Middle East projects

The largest of five new upstream oil projects planned by Saudi Aramco over the next five years is the $3.1bn Khurais development, which will increase production of Arab Medium crude from 100,000 b/d to 1.2mn b/d by 2008, reports *Stella Zenkovich*.

Tenders for the project are expected in 2004/2005.

Other projects include the construction of a 75,000 b/d gas/oil separation plant at Nuayyim, which will increase Saudi Super Light crude production to 275,000 b/d. At the offshore Manifa field, which has 10bn barrels of proved reserves and a current capacity of 200,000 b/d Arab Heavy Crude, plans to boost output will bring an extra 300,000 b/d. Meanwhile, expansion at the onshore Qatif field is expected to produce more than 800,000 b/d of Arab Light crude, while 300,000 b/d of Arab Medium is to come from the offshore Abu Safah field.

In Brief

1/2 on the Norwegian Continental Shelf, including the Blane discovery and the Hummer prospect, which the operator, Paladin Resources, plans to drill in 2004. If this well is successful, the prospect could potentially be developed in conjunction with Blane via a subsea tie back to Gyda.

North America

BP announced on 22 January 2004 *that the 20,000-tonne spar for the BP-operated Mad Dog development had arrived in Pascagoula, Mississippi, following a three-week journey from its construction site in Pori, Finland. The spar will be towed to Gulf of Mexico Green Canyon block 826 in 4,500 ft of water following routine testing and final preparations at the port. Peak production rates are expected to be 80,000 b/d of oil and 40mn cf/d of gas. First oil is scheduled by early 2005.*

Unocal (15%) reports that the *exploratory well in the Puma prospect, operated by BP (51.66%) in Gulf of Mexico Green Canyon block 823, is a 'significant' find. The discovery's proximity to Mad Dog will allow the option of either a stand-alone development or a tie-back, depending on future appraisal results.*

Anadarko reports that the Marco Polo *platform, the deepest tension leg platform (TLP) in the world, was successfully installed in 4,300 ft of water on Gulf of Mexico Green Canyon block 608 on 20 January 2004. First oil and gas is expected in July 2004.*

Anadarko recently approved capital *spending for 2004 in the range of $2.6bn to $2.9bn, having spent just under $2.8bn in 2003.*

Approval for the C$8.5bn Horizon oil *sands project in Fort McMurray, Alberta, has been granted to Canadian Natural Resources, reports* Monica Dobie.

A report commissioned by the Alberta *Energy Utilities Board has recommended the closure of 485 natural gas wells in the northeast of the province to protect oil sands reserves, reports* Monica Dobie. *The wells currently produce 136mn cf/d of gas sitting above bitumen reserves.*

Shell Canada has received regulatory *approval to proceed with its $2bn Jackpine oilsands project. It is believed* to contain 5bn barrels of recoverable bitumen or oily mud. Even with regulatory go-ahead, Shell does not expect to build the open-pit mine, pipeline and co-generation electrical facility until at least 2010, after expanding its current Muskeg River mine.

Unocal reports that it replaced 149% *of its 2003 natural gas and crude oil production through discoveries and extensions, improved recovery and revisions.*

Middle East

A Japanese consortium is to develop *Iran's Azadegan 5–6bn barrel (recoverable) oil field despite being urged by the US not to sign contracts amidst fears that the estimated $2bn investment could be used for nuclear weapons development and terrorist activities. The Japanese consortium will hold a 75% stake in the project, Iran's national oil company holding the remaining 25%. Azadegan is expected to be commissioned in 2007. It will initially produce 50,000 b/d, ramping up to 260,000 b/d once fully operational.*

The much-delayed Phase 1 of Iran's *giant South Pars gas field is expected to have completed by March 2004, to produce 28.3mn cm/d of gas for domestic consumption as well as 40,000 b/d of condensate and 200 t/y of sulphur for export. A series of project delays and cost overruns on South Pars have caused costs to skyrocket from an estimated $780mn to about $1bn.*

The new Soroush oil field platform off- *shore Iran is due to be commissioned shortly. The development plan for the Soroush/Norouz fields comprises 27 oil wells – 10 of which are located on Soroush and 17 on Norouz – and two for water injection. Some 190,000 b/d of oil are currently being produced as the installations are renovated – equivalent to 5% of the country's oil output and 25% of production from the Iranian Continental Shelf.*

Asia-Pacific

First gas has flowed in to the second *trunkline on the North West Shelf project. The A$800mn, 42-inch diameter pipeline doubles the North West Shelf Venture's offshore production capacity to its onshore facilities at Karratha from 1,650mn cf/d to 3,850mn cf/d.*

Oil and gas production on the UKCS

UK oil production during November 2003, at 2,039,455 b/d, was down 11.4% on the year, according to the latest *Oil and Gas Index* (January 2004) from the Royal Bank of Scotland. However, it was up marginally on the previous month's figure of 2,018,972 b/d. Meanwhile, November 2003 gas production of 13,111mn cf/d was up on both the month (Oct 2003: 10,577mn cf/d) and year (Nov 2002: 11,803mn cf/d).

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Nov 2002	2,301,341	11,803	24.20
Dec	2,353,028	12,582	28.32
Jan 2003	2,274,870	12,890	31.17
Feb	2,215,831	13,599	32.23
Mar	2,251,714	12,420	29.92
Apr	2,092,765	10,868	27.50
May	1,948,620	9,659	25.59
Jun	1,940,265	9,221	27.31
Jul	1,957,888	9,250	28.43
Aug	1,858,409	9,842	29.51
Sep	1,966,800	9,546	26.81
Oct	2,018,972	10,577	28.93
Nov	2,039,455	13,111	28.76

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Hat-trick farmout deal for Dana

Dana Petroleum has negotiated a three-for-one farmout deal on exploration licence WA-226-P offshore Western Australia, such that Dana will be free carried on all costs relating to the next exploration well to test the Fiddich prospect. The *Sedco 703* semi-submersible drilling rig has been contracted by well operator Apache Energy, with a currently planned spud date of May 2004. The licence operator, Origin Energy, has estimated mid-case reserves potential of the Fiddich prospect to be approximately 60mn barrels of oil (12mn barrels net to Dana) with an upside case of around 100mn barrels (20mn barrels net to Dana).

Dana has farmed-out to a subsidiary of Australian independent Voyager Energy, an existing co-venturer in WA-226-P. Under this agreement, Voyager will earn a 10% interest in the licence by paying all costs associated with Dana's current 30% interest from 1 January 2004 through to completion of operations on the well.

Following the deal, partner interests are Origin Energy (28.75%), Apache (28.75%), Dana (20%), Voyager Energy (15%) and Norwest Energy (7.5%).

Pemex needs to target deepwater

The head of Mexican state oil monopoly Petroleos Mexicanos (Pemex) has reportedly said that the company needs to look to deepwater deposits as it pursues long-term goals of raising oil production, but lacks the technology to do so. At a recent news conference, Raul Munoz said that Pemex is currently allying itself with international oil companies to explore ways it can acquire the necessary technology. To date Pemex has explored only 18% of its territory likely to contain oil and gas, and of the remaining fourth-fifths, much is in deep water.

Last year, the company produced a record 3.37mn b/d of crude oil, and plans to add an additional 80,000 b/d in 2004 on its way to meeting a 2006 goal of 4mn b/d.

Munoz said Chinese firms were among about 10 companies with which Pemex is exploring possibilities for acquiring deepwater technology, but gave no further details. Under the constitution, Pemex has a monopoly on all upstream oil and gas activities. While it has a refining joint venture with Shell in Texas, Mexico does not allow production joint ventures.

In June 2000, Mexico and the US reached an accord to divide up a 6,565 sq mile (17,000 sq km) area in the Gulf of Mexico that could contain significant hydrocarbon reserves. Mexico was apportioned 62% of the area.

First liquids from Bayu-Undan

ConocoPhillips reports that first liquids production began on 10 February 2004 from the Bayu-Undan field in the Timor Sea Joint Petroleum Development Area (JPDA). Liquids production is the first phase in this two-phase project. Under the first phase, the Bayu-Undan gas recycling facility will produce and process wet gas; separate and store condensate, propane and butane; and re-inject dry gas back into the reservoir. Full daily design rates of 1.1bn cf of gas; 115,000 barrels of combined condensate, propane and butane; and 950mn cf of dry gas recycled into the reservoir are anticipated to be reached by 3Q2004.

Estimated recoverable hydrocarbons are put at 400mn barrels of condensate and LPG, and 3.4tn cf of natural gas.

The second phase of development is an LNG project that is expected to be complete in early 2006, at which time the first LNG cargo from the 3.52mn t/y facility is scheduled for delivery. It will involve a gas pipeline from the Bayu-Undan field to a LNG facility at Wickham Point, near Darwin. Approvals for this phase have been received and construction of the project has already begun. Bayu-Undan will supply 3mn t/y of LNG to Tokyo Electric Power and Tokyo Gas, over a 17-year period.

Major CAD development announced

Aveva, formerly known as Cadcentre, has announced what it claims is a milestone achievement on the translation of intelligent 3D CAD (computer aided design) plant models between the industry's two leading formats. Aveva's Plant Design Management System (PDMS) and Intergraph's PDS have traditionally been the two most popular, but starkly different, formats for intelligent 3D design. PDMS has always adopted an open, purely data-centric approach, while PDS is centred upon Bentley's Microstation 3D drawing application. The implication for the process and power plant industries to date has been that valuable legacy data in one format is of little use to an owner-operator or EPC (engineering, procurement and construction) contractor who wants to work in the other format for future projects.

Following over three years of research and development, the first major 3D process plant model in Intergraphs's PDS format has been brought onto Aveva's PDMS with all of its accompanying plant data via a predictable and repeatable process. As a result, two leading EPC companies have adopted the technology, called XmpLant, in pilot projects. XmpLant, developed in conjunction with Noumenon Consulting, allows the translation of 3D PDS models into Aveva's Vantage PDMS environment complete with their intelligent data. It uses neutral and accessible XML language, which, according to widespread opinion, is the future of data access and management.

Liberian licensing round unveiled

The National Oil Company of Liberia is putting out to tender 17 blocks in the country's 2004 Offshore Licensing Round following the acquisition of some 9,000 km of 2D seismic data, well information and regional interpretations, which are now available from TGS-Nopec in Houston, Texas.

Direct negotiations will be allowed, but will cease on 31 March 2004, after which two conferences will take place in London and Houston in April 2004. At the conferences, a complete package including petroleum laws, production sharing contract, tax laws as well as all technical information will be available.

The area will be under moratorium through the close of the bid round on 1 November 2004.

New 'Frontier' licences for Atlantic Margin

The UK Government has unveiled a new 'Frontier' licence that allows companies to apply for relatively large amounts of acreage at significantly reduced costs and gives them more time to carry out the necessary exploration and development.

The licence will be on offer in the forthcoming 22nd Offshore Licensing Round and will apply to blocks in the Atlantic Margin, West of the Shetland Isles. Companies will have to relinquish three-quarters of the large amounts of acreage that they have applied for after an initial screening phase during which the normal rental fees will be discounted by 90%. In addition, the exploration and development periods will be extended by two years over and above those stipulated for a traditional licence.

In Brief

China's CNOOC and LNG Japan are *understood to have raised their holdings in Indonesia's Muturi gas field, effectively blocking Japan's Mitsui from taking a stake in the multi billion-dollar project. CNOOC, China's dominant offshore oil and gas producer, is to pay $98.1mn to BG Group, increase its stake in Muturi from 44% to 64.77%. The deal will also increase CNOOC's interest in the $3bn Tangguh LNG project by 4.46% to nearly 17%. BG had agreed in December 2003 to sell to Japan's Mitsui its 50% stake in the Muturi production sharing contract for $236mn, bringing with it 10.73% of the BP-led Tangguh LNG project.*

Tests at Vietnam's Su Tu Trang (White *Lion) field in block 15.1 in the Cuu Long Basin are reported to have indicated a recoverable oil reserve of at least 220mn barrels. Commercial production is planned for 2008. Su Tu Trang is located adjacent to the Su Tu Den (Black Lion) oil field, which has reserves of around 400mn barrels and came onstream in October 2003.*

Africa

ONGC Videsh (OVL) is to buy an 11% *stake in a 744mn barrel oil field in Sudan for $125.4mn. OVL will buy out the 6% stake of Gulf Petroleum of Qatar in blocks 3 and 7 for $68.4mn, and UAE's Al-Thani Group's 5% stake for $57mn. The company had previously acquired Talisman Energy's 25% stake in the 260,000 b/d Greater Nile Project for $699mn, and recently acquired a quarter-share in blocks 5A and 5B for $136mn.*

The $2bn Amenam Kpono field off- *shore Nigeria is set to reach peak production of 125,000 b/d in 2Q2004, writes* Stella Zenkovich. *Field reserves are put at 500mn barrels, with a field life of 25 years. Amenam Kpono is operated by Elf Petroleum Nigeria. The company also reports that it is to commence exploration activities in the new deepwater offshore block, OPL 221.*

Shell, Petronas and the Egyptian *Natural Gas Holding Company have made two hydrocarbon discoveries in their North East Mediterranean deepwater concession – drilling in over 2,400 metres of water and setting new water depth records for Egypt and the Mediterranean. No reserves estimates had been released as* Petroleum Review *went to press.*

In Brief

UK

BP's fourth quarter pro forma result, *adjusted for special items, came in at $2,667mn, compared with $2,635mn a year ago. For the year, the result was a record $12,379mn compared with $8,715mn – up 42%. Return on average capital employed (ROACE) for the quarter and year respectively, on a pro forma basis adjusted for special items, was 13% and 16%, compared with 15% and 13% a year ago.*

Shell has reported net income for 2003 *of $12.7bn, 35% higher than in 2002, while Group earnings on an estimated current cost of supplies (CCS) basis for the full year were a record at $13bn (46% higher than last year). In addition, the 2003 target to reduce underlying unit costs by 3% and other costs was achieved in aggregate. Actual pretax savings of $560mn across all businesses exceeded the original target equivalent of $500mn. Group return on average capital employed (ROACE) on a CCS earnings basis for the full year was 16%, two percentage points higher than 2002.*

The European Union competition *authority has granted approval for the formation of HydroWingas, clearing the way for the Norwegian–German joint venture to begin marketing natural gas in the UK. The joint enterprise between Norsk Hydro and Wingas was expected to commence business activities from early February.*

BG Group has posted a 41% increase in *4Q2003 net profit to £183mn.*

Europe

Statoil has reported a NKr48.9bn 2003 *net income before financial items, other items, income taxes and minority interest, up 13% from the NKr43.1bn recorded the year before.*

Norsk Hydro has posted a 2003 net *income of NKr10.968mn, compared with NKr8.765mn in 2002.*

Eastern Europe

Poland's state-owned PERN and the *Ukraine's Ukrtransnafta are reported to have confirmed plans to form a joint venture to extend by 500 km a Ukrainian oil pipeline through Poland, allowing it to diversify its oil supply. The*

UK unveils plans to tackle climate change

The UK Government has published for consultation its draft National Allocation Plan setting out how greenhouse gas emission allowances will be allocated to the operators of UK installations for the first phase of the EU Emissions Trading Scheme (EU ETS), which runs from 2005 to 2007. The plans will help the government meet its national goal of moving towards a 20% reduction in emissions of carbon dioxide (CO_2) by 2010.

The initial allocation of allowances for the first phase of the scheme is consistent with an overall reduction in UK CO_2 emissions of 16.3%. However, the overall level of allowances to be allocated in the UK in phase 2 of the scheme (which runs from 2008–2012) will be strengthened to be consistent with the trading sector's contribution to achieving the 20% goal.

The EU Emissions Trading Scheme is the most significant measure in the EU Climate Change Programme. The objective of the scheme is to reduce, in the most cost-effective way, EU emissions of greenhouse gases that contribute to the problems associated with global warming. The UK Government has stated in its Energy White Paper that the EU ETS will be a central plank of its future emissions reduction policies.

Each EU Member State is required to draw up a National Allocation Plan (NAP) for submission to the European Commission by the end of March 2004. The Plan has to set out the total number of emission allowances, each representing one tonne of CO_2, to be allocated to the industry sectors covered by the EU ETS. It also has to show how this total allocation is to be distributed between individual installations included in the scheme.

From the beginning of 2005, the EU ETS will for the first time impose requirements on the largest individual emitters of CO_2 to monitor and account for their emissions. The installations covered include the electricity generation industry; oil refineries; the iron and steel industry, the minerals industry, and paper, pulp and board manufacturing. Together, the installations covered by the scheme account for about 50% of all UK CO_2 emissions.

However, a number of organisations have voiced concerns over the plan. For example, the UK Offshore Operators' Association (UKOOA) claims that: 'Numerous onshore installations have been included in the "offshore" calculation while a number of qualifying offshore installations appear to have been overlooked altogether and have received no allocation at all.' In addition, it states that: 'Many installations appear to face cuts in emissions of 30–45%, which neither reconcile with the method of calculation which is said to have been used nor is consistent with 16.3% overall reduction in UK CO_2 that the government states it is looking for through the ETS.'

Looking downstream, UKPIA, the trade association representing the main oil refining and marketing companies in the UK, also has concerns, stating that the proposed CO_2 emission allowances contained in the consultation document 'do not seem to be in accordance with the government's stated policy and if implemented in this form could seriously damage the UK oil refining industry'.

UKPIA's main concerns include: ● 'The lack of clarity on how the allowances for the oil refining sector have been calculated ● There seem to be serious errors in the calculation of allowances for individual refineries ● An apparent inconsistency, and hence lack of equity, in the treatment of different refineries. Most have received unrealistically large reductions in their allowances for the first period whereas, curiously, two have received very significant increases compared to their historic data. ● The potential impact of the central set aside pool for new entrants, if applied to the refining sector, and the resultant auctioning of allowances that this will introduce.'

'Unlike a number of other sectors, particularly power generation, the UK refining industry is subject to competition from other European plants which have spare capacity adequate to supply a large proportion of the UK fuels market,' comments UKPIA. 'If these proposals were implemented as currently drafted, it is quite likely that imports would rise and UK refinery output would fall, potentially affecting both UK jobs and security of supply, without any additional environmental benefit to the UK.'

To view the consultation document, visit **www.dti.gov.uk/consultations/#current**
There is also a summary of the EU ETS at **www.dti.gov.uk/energy/sepn/euets.shtml**

Latest EU and EC developments

A series of exemptions from the European Union's (EU) new energy taxation directive have been proposed by the European Commission (EC) for the Eastern and Southern European countries joining the EU in May (barring Cyprus), reports *Keith Nuthall*. They would be added to the already long list of exemptions negotiated by existing Member States that prompted EU internal market Commissioner Frits Bolkestein to liken the legislation to 'Gruyere cheese'. The Eastern European exemptions go wider still, including gas, as well as the liquid fuels dominating existing opt outs. They are however time limited to 2012.

In other EU news:

- A Spanish professor of shipping sciences has told a European Parliament inquiry into the *Prestige* disaster that its Captain Apostolos Mangouras should not be blamed for the tragedy. Instead, Felipe Louzán Lago blamed the Spanish authorities for not allowing him to sail to a refuge port. He added no responsible services had helped the vessel and there was 'a total lack of coordination between them'.
- Details of an agreement to install a gas interconnector linking Greece and Turkey through Thrace have been struck by the Greek Natural Gas Company (DEPA) and Turkish gas company BOTAS. Work could begin this year, being completed by 2006.
- An alliance of European fuel companies, research groups, transport specialists, car-manufacturers and utilities has started work on a comprehensive plan for introducing hydrogen fuel-cell technology in Europe. They met at the first general assembly of the European Hydrogen and Fuel Cell Technology Partnership.
- The European Investment Bank (EIB) is to lend (Greek) Cyprus up to €100mn for building a 170–220 MW combined-cycle gas turbine generator using distillate oil and LNG. The EIB is also lending €90mn to Croatia state gas company Plinacro for expanding and modernising the gas transmission system from 2002 to 2011, including a new link to offshore Adriatic Sea gas fields.
- The EIB is planning to lend up to €100mn to the EPEG consortium (including the Egyptian General Petroleum Company, among others) to fund the Jordanian section of the Arab gas pipeline, connecting industrial consumers and power plants at Aqaba, Amman, Rehab and As Samra with Egyptian gas fields.
- France is being taken to the European Court of Justice (ECJ) by the EC for failing to abide by the EU waste oils directive's insistence on the prioritisation of waste oil processing through regeneration. Austria is facing an ECJ case over its alleged failure to report on the sulphur content of fuels used in its territory during 2001, as required by a 1999 directive.
- The European Bank for Reconstruction and Development (EBRD) is considering lending Azerbaijan state oil company Socar two loans to aid development of the offshore Caspian Shakh Deniz gas/gas condensate field. Some $110mn would help fund stage 1 of a four-stage field development, with nine wells being initially drilled offshore. A further $60mn would help fund a South Caucasus Pipeline, built parallel to the BTC (Baku–Tiblisi–Ceyhan) pipeline from Azerbaijan to the Turkish–Georgian border.

New technology tackles climate change

Robert R Holcomb, an Assistant Professor at Vanderbilt University School of Medicine, recently unveiled before an audience of New Zealand Government, business and environmental leaders what is claimed to be a revolutionary new technology that will help solve the problem of greenhouse gases and global warming.

'The unique technology of the Carbon Dioxide Converter permanently splits the molecular structure of carbon dioxide into its basic elements – carbon and oxygen,' explained Dr Holcomb. 'This converter functions in a similar way for other toxic greenhouse gases such as sulphur dioxide, the major cause of acid rain. This proprietary technology uses a patented and patent-pending closed loop system that burns any fossil- or carbon-based fuel with zero harmful emissions. These fuels include coal, oil, gas, and any biomass including waste and landfills. A significant byproduct of this process is carbon black, which is used in the production of tyres, printing ink, and as a pigment for plastics.'

Joining Dr Holcomb was John Small, Head of the Economics Department of Auckland University, who presented the findings of his independent study on the economic impact of Dr Holcomb's discovery for New Zealand and the world. Dr Small estimates that the global economic benefit arising from using the technology for coal-fired electricity generation at between $134bn and $347bn, with mid-range deployment assumptions implying a benefit of $223bn.

In Brief

pipeline could eventually carry Caspian crude to Western Europe. The project, expected to cost more than $500mn, is to complete by the end of 2005.

The Czech Government has selected *three of the six bidders for a $500mn tender for a 63% stake in Unipetrol. Two of the three firms – Poland's PKN Orlen and Hungary's Mol – are from neighbouring countries, and are considering a merger. The third bidder is Shell.*

North America

Marathon Oil has approved a 2004 *capital, investment and exploration expenditure budget of approximately $2.26bn, a 3.7% increase over actual expenditures of $2.18bn during 2003 (excluding acquisitions of $250mn).*

Exxon Mobil has reported 4Q2003 net *income of $6,650mn, an increase of $2,560mn from 4Q2002. The result includes a special item of $2,230mn relating to the settlement of a long-running US tax dispute. ChevronTexaco reported preliminary net income of $1.7bn for 4Q2003, compared with $0.9bn in the year-ago period, while ConocoPhillips posted a 4Q2004 net income of $1,021mn, compared with a net loss of $428mnfor the same quarter in 2002. Marathon Oil reported 4Q2003 net income of $485mn (2Q2002: $194mn), Anadarko $294mn, Apache $260mn (2002: $179mn), Unocal $180mn (2002: $96mn), Amerada Hess $68mn (2002: –$371mn, and Petro-Canada $152mn.*

A total of 228 US companies and other *entities reported to the Energy Information Administration (EIA) that they had undertaken 2,027 projects to reduce or sequester greenhouse gases in 2002, according to the EIA's* Voluntary Reporting of Greenhouse Gases 2002 *– a copy of which can be downloaded from EIA's website at* **www.eia.doe.gov/oiaf/1605/vrrpt/pdf/0608(02).pdf**

Jeffrey Skilling, the former Enron *Chief Executive, is understood to have surrendered to the FBI following reports that he had been indicted for his part in the collapse of the former energy giant.*

A US federal judge has ordered *ExxonMobil to pay about $6.75bn to thousands of Alaskans affected by the 1989* Exxon Valdez *oil spill. The company plans to appeal.*

In Brief

NEWS Downstream

UK

Arval PHH, the UK's largest fleet and *fuel management company and operator of the AllStar fuel card, reports that the average prices of unleaded fuel and diesel across the UK reached their highest level since May 2003 – 76.79 p/l and 78.34 p/l respectively – for the week ending 23 January. These increases follow a long period of stability in fuel prices. For over four months, from August to December 2003, they varied by less than a penny per litre from week to week. However the recent rise in oil prices, with Brent crude now trading in excess of $30/b, is starting to be felt on the forecourts, says the company.*

The UK Government has given its *consent for construction of a flue gas desulphurisation plant at the 1,000-MW coal-fired power station at Rugeley in Staffordshire.*

Europe

Total is to invest €500mn to increase *the conversion capacity at its Normandy refinery. The new distillate hydrocracker and steam methane reformer are due to be commissioned in mid-2006.*

The EBRD is lending €32mn to Turkish *fuel distribution company Opet Aygaz Bulgaria (OAB), reports* Keith Nuthall. *The monies will be used to set up petrol stations in Bulgaria, a refined product service for Bulgarian commercial and industrial customers, along with better logistics and storage.*

North America

ConocoPhillips plans to sell 1,180 *Mobil-branded service stations under two deals valued at $453mn. The deals form part of a programme to reduce the number of outlets the US company owns and operates, and to divest stations or wholesale relationships involving brands other than Phillips 66 or Conoco 76. Getty Petroleum Marketing, a wholly-owned subsidiary of Russian company Lukoil is to buy 795 sites or wholesale relationships in New Jersey and Pennsylvania for about $266mn. The sites throughput some 1.2bn gallons of fuel annually, practically doubling the company's market share in the northeastern US.*

UK pump prices lowest in EU during 2003

The average pump price of petrol (unleaded 95 octane) and diesel, excluding duty and VAT, on Britain's forecourts was the lowest amongst major EU countries during 2003, reports UKPIA (the UK Petroleum Industry Association). Data from OPAL Wood Mackenzie, that was based on the monitoring of major brand pump prices across 10 EU member countries, revealed that the UK average pre-tax pump price of unleaded 95 petrol was over 1 p/l cheaper, at 19.01 p/l, than the next lowest countries – France, at 20.09 p/l, and Germany at 20.33 p/l. The UK was also the cheapest pre-tax for diesel, averaging 20.37 p/l, compared with 20.59 p/l in Germany and 21.01 p/l in Luxembourg.

Chris Hunt, Acting Director General of UKPIA, commented: 'This data underlines just how competitive fuel retailing continues to be in the UK. Pre-tax pump prices have been consistently amongst the lowest in the EU over the last seven years. Against this background, our members continue to make substantial investment at their refineries to introduce sulphur-free road fuels later this year which, combined with new vehicle technologies, will help improve fuel efficiency and deliver further improvements in exhaust emissions.'

Competition in fuel retailing is also reflected in the level of gross margin on each litre of petrol sold – the difference between the selling price of petrol and the open market cost. Figures show that this averaged just over 5 p/l in 2003, compared with 7 p/l in 1992. The gross margin is not the profit available to a retailer but represents the sum available to cover costs such as transporting fuel from a refinery, marketing and promotion, and operating a filling station.

These tough conditions have contributed to the closure of filling stations in both urban and rural areas of the UK, whose number has declined from over 18,500 in 1992 to 11,400 in 2002.

Petrol and diesel will remain dominant in sales

In its evidence to the UK House of Commons Select Committee on Transport's inquiry into 'Cars of the Future', the UK Petroleum Industry Association (UKPIA), the trade association representing refiners and marketers of fuels in the UK, confirmed its view that up to at least 2030, petrol and diesel would continue to supply the bulk of the road transport fuel market. It also stated that the combination of new cleaner fuels and new more fuel-efficient vehicle technologies was capable of meeting reduced carbon dioxide (CO_2) emissions targets from road transport, as well as delivering cleaner air, over the same period.

UKPIA forecasts that CO_2 emissions from road transport will fall over the next two decades, despite predicted traffic growth. However, it cautions that the road transport sector in the UK accounted for 21% of CO_2 emissions, so all sectors would have to make efficiency gains to meet government targets.

Malcolm Watson, Technical Director of UKPIA commented: 'Petrol and diesel fuelled vehicles are capable of delivering reduced CO_2 in the medium term. The industry is keeping an open mind on a range of alternative fuels and many of our member companies are involved in producing them or engaged in collaborative research on new fuels and technologies. Key factors for the introduction of new fuels include ease of use for customers, minimal or no modification to vehicles and the ability to accommodate the fuels into the existing supply infrastructure or, in some cases, to blend them with conventional petrol and diesel. For these reasons we favour alternatives which are liquid fuels.'

UKPIA also reiterated that it was not against the use of fuels derived from energy crops, but considered that conversion of conventional crops to liquid fuels was not the most efficient route for saving CO_2. Biomass applied in the production of primary energy such as heat and electricity provided a better CO_2 saving, in the Association's opinion.

Responding to the Committee's concerns about security and diversity of supply of crude oil and gas, UKPIA was of the view that forecast reserves were adequate for the projected demand for at least the next few decades. In addition, these could be supplemented by less conventional sources such as heavy tar sands or conversion of gas to liquids.

NEWS Downstream

Managing fuel prices effectively

Since Esso launched PriceWatch in 1996 oil companies have had the benefit of monitoring their own prices relative to the competition by viewing prices daily against the Catalist Petrol Station database. Given tighter and tighter fuel price margins, the independent dealers are also looking at more and more sophisticated ways to monitor prices. Therefore it is probably no coincidence that at least three new tools have recently come onto the market to provide petrol retailers with better intelligence on price. Firstly, there is 'PriceViewer' from Catalist, which enables dealers to monitor up to ten selected competitors' prices on a daily basis via the Internet.

Secondly there is Platts' monthly market data being provided by BigOil.net via a purpose built website in association with Platts. Thirdly, the relaunch by Wood Mackenzie Consultants of Opal's assessments of national average 'major brand' and supermarket pump prices and margins on a weekly and monthly basis is also Internet based.

With the speed that businesses have to make decisions and with such ready access to technology it is no surprise that all these services rely heavily on the Internet for timely and efficient delivery.

Catalist is the leading provider of objective and independent data, modelling and consultancy on retail petrol markets worldwide. For more information on pricing products visit **www.catalist.com** or t: +44 (0)117 923 7113 and ask for Arthur Renshaw.

CAT	Brand	Site Name	Dist. miles	Postcode	UL	DI	SUL	LRP	LI
6211	**BP**	**NORTON SERVICE STATION**		DY8 2AF	75.9 08/01/2004	76.9 08/01/2004	80.9 06/01/2004		
6210	BP	RING ROAD SERVICE STATION	0.6	DY8 1ET	74.9 08/01/2004	75.9 08/01/2004	79.9 08/01/2004		
8261	TEXACO	PETROL EXPRESS STOURBRIDGE	0.6	DY8 2LJ	74.9 08/01/2004	75.9 08/01/2004	79.9 08/01/2004		
6210	BP	RING ROAD SERVICE STATION	0.6	DY8 1ET	74.9 08/01/2004	75.9 08/01/2004	79.9 08/01/2004		
2329	ESSO	TESCO EXPRESS	0.6	DY8 1RD	74.9 04/01/2004	75.9 04/01/2004	78.9 01/01/2004		
15832	SAINSBURYS	SAINSBURYS AMBLECOTE	1.8	DY5 3JR	74.7 08/01/2004	75.9 08/01/2004	79.9 05/01/2004		
CAT	Brand	Site Name	Dist. miles	Postcode	UL	DI	SUL	LRP	LI
8795	**TESCO**	**TESCO BRISTOL 3 (BRADLEY STOKE)**		BS32 8EF	73.7 08/01/2004	74.9 08/01/2004		78.9 22/12/2003	
8794	SAINSBURYS	SAINSBURYS EAST FILTON	2.1	BS34 8SS	73.7 08/01/2004	74.9 08/01/2004	79.9 08/01/2004		
2065	ESSO	STOKEBROOK SERVICE STATION	1.0	BS34 5BB	73.7 08/01/2004	74.9 08/01/2004	81.9 08/01/2004		
11216	TEXACO	FILTON PARK SERVICE STATION	2.9	BS7 0SH	74.9 08/01/2004	75.9 08/01/2004		81.9 07/01/2004	

Electric utilities need to reassess strategies

The electric power industry's dramatic earnings and valuation swings in recent years, plus increasing experience with the limitations of a 'back-to-basics' approach, is creating recognition that strategies must be reset to meet new challenges and objectives, Cambridge Energy Research Associates (CERA) Senior Director of Global Gas and Power, Lawrence J. Makovich, recently stated.

'In the wake of a crisis of confidence, trading scandals and valuation collapses, companies in many segments of the power industry turned to a "back-to-basics" model, but they are now finding that this approach falls short in providing earnings growth,' Makovich said. He noted that the combined net income of the companies in the Dow Jones Utilities Index fell from $12bn in 2001 to a loss of more than $5bn in 2002, and the 15 companies' combined market capitalisation was cut in half from almost $250bn to less than $123bn from 2001 to 2002. Net income recovered to about $8bn during the first nine months of 2003, but market cap has remained less than two-thirds of what it was at the start of 2001.

'As back-to-basics is recognised as a holding action, companies must develop new strategies that can sustain improved returns over longer periods of time. This requires understanding that the industry landscape has changed dramatically, and then fitting strategy to the opportunities that are available. However, when the landscape shifts, people are often slow to recognise it because of blind spots that result from missing or misinterpreting information.

In Brief

ExxonMobil Research and Engineering *Company (EMRE) and Hamon Research-Cottrell (HRC) report that Shell Oil Products US has selected ExxonMobil's well-proven wet-gas scrubbing technology for its Puget Sound refinery in Washington State. This technology will enable the refinery to reduce emissions of sulphur oxides (SO_x) and particulates its fluid catalytic cracking unit (FCCU) when the wet-gas scrubbing installation is completed in 2006.*

The Bush administration is reported to *have 'quietly shelved' a proposal to ban the clean-air gasoline additive MTBE, which had earlier been claimed to contaminate drinking water in many communities by leaching into ground water acquifers.*

Middle East

The Palestinian National Authority *(PNA) has signed a Memorandum of Understanding with Egypt to purchase 8.57mn cmly of gas for use in the Gaza Strip power plant, writes* Stella Zenkovich. *The agreement is valid for two years.*

Natural gas is reported to have *begun flowing to the Israel Electric Corporation (IEC) Eshkol power plant in Ashdod. It is understood to be the first time that gas has been used to produce electricity in Israel. The gas is being supplied from the offshore Ashkelon field.*

Russia & Central Asia

Hungarian oil and gas company Mol is *reported to have increased its stake in Slovakia's monopoly oil refinery to 98%, up from 70.02%.*

Asia-Pacific

Petronas (20%), Shell (10%) and Assar *Senari (70%) are to participate in a joint venture company that will operate and manage an automated bulk petroleum terminal in Kuching, Sarawak. The terminal is to be commissioned in late 2005. It will have an initial capacity of 5mn litres, with a provision for expansion at a later stage of its operation.*

Indian Oil Corporation, India's largest *state-controlled refiner, is understood to be planning to bid for stakes in*

In Brief

BP's Malaysia and Singapore operations in order to expand its overseas business. The company is to bid for BP's entire 70% stake in its Malaysian unit, which owns 272 service stations and has a 10% share of the country's retail fuel market. It will also bid for BP's Singapore unit, which owns 30 outlets and has a 12% share of the retail fuel market.

***Sinopec is understood to be planning** to invest some Y200–300mn on the construction of 130 service stations in northern China's Hebei Province in 2004. The company currently owns and operates 1,599 of the 7,500 total network in the province.*

Africa

***Kenya may be forced to shut down** the country's only refinery in Mombasa, which is the prime fuel supplier in East Africa, unless it is upgraded to allow the production of lead free gasoline and low sulphur products, writes* Stella Zenkovich.

***Private investors headed by Obat Oil** Chairman Prince Eniti Akinruntan have decided to build a $1bn refinery in the Ilaje area of Nigeria's Ondo state, writes* Stella Zenkovich. *Plans are to commission the facility before the close of 2004.*

***The Rwandan Government – a signa**tory to a five-nation action plan with Burundi, Ethiopia, Eritrea and Kenya to phase out leaded petrol by the end of 2004 – has given importers until the end of March to clear their stores of leaded petrol, reports* Stella Zenkovich.

NEWS Downstream

Cleaning up commercial vehicle emissions

A high level campaign for the UK Government to increase funds to clean-up the ageing buses, lorries, vans and taxis operating in UK cities was launched on 12 February 2004. The Environmental Industries Commission (EIC), which represents companies that develop pollution control technologies, is warning that failure to clean-up commercial vehicles will put at risk the UK's legal obligations to meet air quality standards.

Measures to clean-up commercial vehicles to drive down pollution levels in Britain's cities recently came up against a major road block when government funding to fit such technologies to commercial vehicles unexpectedly ground to a halt. The Department for Transport provides £12mn/y funding through the Energy Savings Trust (EST) CleanUp programme to retrofit pollution control equipment, such as particulate traps, to older commercial vehicles in order to improve air quality in pollution hotspots. The UK faces tough European legal air quality targets in 2005 and 2010 and the CleanUp programme is an important part of achieving these standards. However the funding for the CleanUp programme unexpectedly ran out early in 2003/2004 as it was unable to meet demand from vehicle operators to fit technology to cut their pollution. The EST is now proposing to reduce the levels of grants offered in order to 'manage demand' for the programme in 2004/2005.

The EIC has, therefore, launched a high level campaign for increased funding for the CleanUp programme to maintain grant levels, and to match the demand from vehicle operators for clean-up technology. The first step in this campaign is the tabling of an 'Early Day Motion' in the House of Commons. EIC will also be raising the issue directly with key Ministers and writing to MPs asking for their support. At present, CleanUp pays for up to 75% of the installation costs for cleaning up older vehicles, depending on the technology. At this level, vehicle owners are motivated to pay for the remainder, as well as additional costs such as maintenance, because they can earn the money back through reduced vehicle excise duty (VED) payments. EIC argues that the EST proposals to reduce the grant levels below their present levels could have a dramatic effect on demand.

Changes planned to Portuguese energy sector

Eni reports that is has signed with the Portuguese Government a preliminary framework agreement for the reorganisation of Galpenergia as part of the restructuring of the Portuguese energy sector.

Eni is to exit from the refining and marketing sector of oil products, selling its interest to a Portuguese state company. The Italian company is to focus instead on the Portuguese gas market, increasing to 49% its participation in Gas de Portugal (at present indirectly owned through Galpenergia, of which Eni is a shareholder with a 33.34% participation).

Appropriate governance agreements between Electricidade de Portugal (which will be shareholder of GdP with a 51% share) and Eni will ensure the cooperation among partners and the joint management of Gas de Portugal.

UK Deliveries into Consumption (tonnes)

Products	†Dec 2002	†Dec 2003	†Jan–Dec 2002	†Jan–Dec 2003	% Change
Naphtha/LDF	210,738	163,821	1,578,456	2,260,086	43
ATF – Kerosene	883,501	875,194	10,383,625	10,268,721	–1
Petrol	–	–	–	–	–
of which unleaded	1,565,288	1,607,828	19,394,498	18,737,098	–3
of which Super unleaded	77,816	66,435	626,446	809,327	29
ULSP (ultra low sulfur petrol)	1,487,472	1,541,393	18,768,052	17,927,771	–4
Lead Replacement Petrol (LRP)	21,980	8,611	509,786	190,280	–63
Burning Oil	483,175	547,047	3,859,322	3,979,706	3
Automotive Diesel	1,319,756	1,428,070	16,948,757	16,907,904	0
Gas/Diesel Oil	525,531	518,256	6,060,124	6,285,136	4
Fuel Oil	226,532	238,959	1,984,530	2,402,177	21
Lubricating Oil	67,657	63,710	800,988	855,735	7
Other Products	619,740	649,254	8,045,597	8,032,755	0
Total above	5,923,898	6,100,750	69,565,683	70,146,465	1
Refinery Consumption	337,888	430,115	4,792,311	4,625,711	–3
Total all products	6,261,786	6,530,865	74,357,994	74,772,176	1

† Revised with adjustments

All figures provided by the UK Department of Trade and Industry (DTI)

Seismic industry puts its faith in the reservoir

WesternGeco's land vibroseis units in nighttime operations

The idea that it is 'Blue sky from now on' for the seismic industry may be a little optimistic. But finally in 2004 it looks as though the gloom, which has hung over the seismic business for the past five years, has begun to lift, explains *Andrew McBarnet*.*

The era of oil company consolidation, downsizing and cost reductions at the end of the 1990s to improve market performance hit the seismic industry harder than any other of the oil services industry sectors. With hindsight it's easy to see why. Drying up of demand for seismic exploration surveys, marine and on land, exposed a vulnerable business model to pressures it couldn't withstand.

Not so obvious then was that the 3D seismic revolution, particularly for marine applications – which had propelled the companies through some prosperous years in the mid-1990s – had suddenly become 'old hat' technology, easy to acquire at bargain prices as a result of intense competition among the service companies.

Effectively the industry's biggest selling point had lost its shine at the worst possible moment. This became obvious in 1999–2001 when all the main geophysical contractors such as WesternGeco, Petroleum GeoServices (PGS), Compagnie Générale de Géophysique (CGG) and Veritas DGC began to build up large libraries of multi-client marine 3D survey data, often with little or no pre-funding. It was seen as the only way to keep their huge financial commitment in new vessels working, but it was also just a matter of time before the investment community began to question the value of the multi-client data credited in the books as future sales.

Overcapacity

The predictable fall-out came with very substantial write-downs all round. In the case of PGS, it contributed to the company's brief retreat into Chapter XI with debts of $2.8bn, from which it re-emerged restructured in November last year. PGS narrowly avoided break up, while in the last few years the other companies have all had their challenges.

The hole in multi-client data sales was simply one more aggravation. For example, at the end of 1999 Geco-Prakla and Western Geophysical, the two biggest companies in the field, merged in response to rampant overcapacity, especially in the market for 3D towed streamer marine surveys. But the new WesternGeco (70% Schlumberger, 30% Baker Hughes) has struggled to retain market share in marine, and on land it has basically abandoned North American land crew operations to focus on strategic, presumably profitable, operations elsewhere.

CGG has had to sell off a number of assets and restructure. It has probably survived more or less intact thanks to its strong performing subsidiary Sercel, which is currently the acknowledged front runner in the manufacture of land seismic acquisition systems. Meanwhile Veritas DGC has struggled, hampered in 2002–2003 by its long drawn out, but ultimately unconsummated, merger negotiation with PGS.

Less cyclical services

It is of course misleading to say that the whole seismic industry has been in a slump, although no company has avoided having to make some adjustments to fluctuating demand. The two dominant E&P software solutions companies – Schlumberger Information Solutions (which includes GeoQuest) and the Halliburton subsidiary Landmark Graphics – have probably always turned in a profit because the demand for their services is less cyclical. Even in the marine seismic survey market TGS-NOPEC has consistently been able to come up with positive numbers for its multi-client survey operations. The company's secret for success is that it never invested in building vessels, operating mainly on short-term leases and avoiding the costs incurred when vessels are idle.

What we may be witnessing now is a race to catch the new post-3D seismic technology wave and to adjust to a new business environment in which there could be a much wider variety of players. Today all the talk is about the reservoir and how seismic technology with high resolution imaging can optimise the recovery of reserves from fields being planned, in production or in need of rejuvenation to prolong their producing life. This is in response to the oil companies' priority these days, under pressure in the financial markets for poor performance, to optimise their investment in existing resources rather than spend on exploration, which has a higher degree of risk and a longer term return on investment (not popular with the present shareholder community).

Maximum information

In fact, the seismic industry has a good story to tell on improvements in reservoir imaging – extending from high-resolution acquisition techniques to extraordinarily complex treatments of legacy and new data to extract more information. From an acquisition point of view 4D and multi-component seismic surveys are the future. The 4D survey is in fact a series of 3D seismic surveys carried out over a period of time in order to image changes in a producing reservoir. Ideally a 4D survey project should be multi-component in scope, in other words each survey should be recording both the p-wave (pressure) and the s-wave (shear) in order to provide the maximum amount of information.

This is where economics have so far stymied progress, because multi-component surveys in the marine context involve the placing on the seabed of geophones to catch the s-wave from a seismic shoot. Conventional 3D seismic streamer recording simply uses groups of hydrophones strung along the cable to record the p-wave. The ultimate solution, so far considered prohibitively expensive for all but the biggest companies, is to carry out some form of ocean bottom survey (OBS) using cables or nodes containing clusters of geophones and hydrophones combined, spread over a targeted area of the reservoir.

Reservoir management

In evaluating how the 4D/multi-component technology might play out, everyone is looking for clues from the operations on the NKr350mn Life of Field Seismic (LoFS) project launched by BP last year on its Valhall field, offshore Norway. BP has buried 120 km of four component (4C) seabed cable (produced by OYO Geospace) covering a 35-km² area around the Valhall reservoir. The company expects to carry out six multi-component seismic surveys over 18 months to assess whether changes in reservoir behaviour can effectively be imaged for better informed reservoir management decisions.

The buried cable is thought to resolve many, but not all, the issues of repeatability in 4D surveys because the recording units remain in the same position for every seismic shooting programme. In another innovation to speed up potential delays in the processing stage, the data is linked directly to the Valhall platform and then on by fibre optic link onshore for processing by PGS.

If successful, BP has made it clear that it has many other projects in mind. In the Valhall case, BP is hoping that application of LoFS will help to increase output from the field in which it is investing some NKr10bn in an injection platform and two flank wellhead platforms as part of a renewed oil recovery programme.

Highly customised

No other company to date has gone for the buried cable LoFS option. One interesting implication of the ocean bottom survey approach and high-resolution surveys over reservoirs more generally is that the service is likely to be highly customised in terms of the equipment and method used.

It is already clear that the market may open for niche companies with unique solutions that produce the results oil companies are looking for. For example, the small Norwegian seismic acquisition company Multiwave Geophysical has recently brought into operation two new vessels – *Polar King* and *Pacific Titan* – in the expectation of large-scale 4C 3D surveys. Another

Geco Eagle **seismic vessel**

Western Neptune **– one of four WesternGeco Q-technology vessels**

Land vibroseis units

little known Norwegian firm Seabed Geophysical is currently working for Pemex in the Gulf of Mexico on a multi-component survey using, for the first time, a specially developed system of recoverable nodes which are placed on the sea bottom.

The larger marine contractors have been successfully selling oil companies into a modified 4D survey system, based on towed streamers repeating the same survey over time using the latest in high resolution seismic technology and good positioning. WesternGeco believes that this is an excellent application for its Q technology, which offers a fully calibrated, steerable, streamer acquisition system. Its principal innovation is that the system records the output from every receiver individually rather than in the conventional groups to produce a higher fidelity image. Last year the company made much of the successful outcome its first Q-on-Q survey for Statoil on the Norne field using data shot in 2001 and 2003.

High resolution strategy

Rivals such as PGS and CGG believe they have competitive technology. In February this year, for example, using the vessel *Ramform Victory*, PGS carried out a customized 4D base survey for Statoil over the Albatross/Snøhvit field, offshore Norway, deploying 10 streamers over an eight-streamer pre-plot survey as part of the high resolution strategy. Many of the surveys in the last year or two in the mature province of the North Sea have been 4D related, and operators of some of the big new fields offshore West Africa, the Gulf of Mexico and similar frontier deepwater prospects are also asking for surveys to be planned on the basis of being the base for later 4D analysis.

The quest for better resolution is not confined to marine surveys. WesternGeco has a Q-Land application. Input Output (I/O), the US manufacturer of seismic acquisition systems, last year introduced the first commercial version of its VectorSeis digital sensor and System Four cable-based recording unit for land seismic, offering multi-component capability. It hopes that the land product will allow it catch up with Sercel, to whom it has been losing ground in recent years, and intends to introduce an ocean bottom survey version this year. Bob Peebler, CEO of I/O, a highly successful head of Landmark Graphics in the 1990s and something of an industry guru, believes that VectorSeis represents the technology of the future based on digital full wave imaging.

Business centre shift

With the exception of a sale to Canadian company Trace Energy, I/O's successes so far with VectorSeis have been in Poland, Russia and China. It is the sales route being taken by many manufacturers and service companies these days, which in Peebler's view among others, suggests that the centre of the business may well be shifting from its traditional base in Houston.

Part of the problem faced by the longstanding land seismic leaders like WesternGeco and CGG is that their territory is being poached by crews from Eastern Europe, Russia and China with state of the art technology. BGP, the Chinese geophysical contractor, has 94 crews, fo which over 30 are overseas. It has carried out work in Former Soviet Union countries, Asia, Africa and South America.

Innovative solutions

Focus on the reservoir does not of course end with acquisition. Maximising the potential of acquired seismic data in modelling the reservoir has spawned a thriving industry characterised by big players such as Landmark Graphics, Schlumberger and Paradigm Geophysical, focused on providing one big integrated solution for all geoscientific and engineering data, and a subset of companies offering very specialised, often rather complex but innovative solutions to particular issues.

Perhaps the best regarded work has been in the area of inversion, in which software is developed to effectively calibrate seismic against well data to produce a better geological understanding of a reservoir's rock structure and to predict porosity, fluid and lithology. Leading players such as Fugro Jason, Ødegaard, dGB Earth Sciences in Europe, and Rock Solid Images and Hampson-Russell in the US have been honing the technology for a few years. In January this year Landmark Graphics released DecisionSpace Well Seismic Fusion, a suite of interpretation and analysis tools for predicting reservoir rock properties from prestack seismic data, synthetic data and well data, which it developed in association with Statoil, suggesting that the competition is warming up.

There is probably a word of caution in all this to be said about the refocus on the reservoir for the seismic industry. Simply put, it is by no means a majority sport. Service companies have seized on the potential of the technology as a 'get out' pass from the unsustainable, traditional seismic acquisition and processing business. But the majority of oil companies, national and commercial, around the world have yet to be persuaded, worried by the cost and lack of skilled personnel for what is often highly sophisticated as well as insufficiently proven technology. Their needs may well increasingly be met by regional seismic operators able to provide bread and butter seismic work at very attractive prices. That's a risk that the main players have to take as they aim for new seismic horizons. ●

** Andrew McBarnet is Publishing Editor of* First Break*, the publication of the European Association of Geoscientists and Engineers.*

Images courtesy of WesternGeco

Prize-winning personality

Vicky Robinson of BP Tanzania, winner of the IP 2003 Outstanding Individual Achievement Award, explains more about the 'Beyond Petroleum and Blessed Pupils' project – a community initiative that looks after orphans in Tanzania, helping provide them with an education and the chance of a better future.

As part of my role as an HIV/AIDS Peer Educators Coordinator at BP Tanzania I received a donation of $100 from the company, which I used to organise an HIV/AIDS workshop in my community – the aim of which was to create awareness of the disease and to help stop the spread of new infection. Following the workshop and using donations worth $150 from its participants, I launched a project to support 20 orphans whose parents had both died of HIV/AIDS. The group of children has been called 'Blessed Pupils', and they will complete a nine-year programme of Tanzanian education under the charity organisation The Hekima Orphans Foundation.

The money generously donated by the workshop participants was just enough to buy school uniforms for five of the orphans. I clothed those who were most in need – some of the girls in the group were already 11 years old and attending school half-naked and without underpants.

The assistance provided to these orphans is helping them to acquire formal Tanzanian education through primary school and secondary school. The assistance includes the paying of school fees; buying school uniforms, exercise books and any other necessities; and making sure that they attend classes and perform and behave well.

Looking to the future

The Blessed Pupils project is about trying to give orphans a better future. Think of where you would be today if you had never gone to school. You must agree with me that you are where you are today because you had the chance to be educated – without education you end up nowhere.

The IP Award that I received last year* emphasises that education is a key to poverty alleviation, profit making and the growth of societies. Moreover, education is the only tool to help repay the social, safety and environmental impacts of our commercial consumption and discharges. These 'Blessed Pupils' didn't apply to become orphans; they are the outcome of the ignorance of their parents regarding HIV/AIDS. If they had remained unsupported by family or society, they may have become street children and ended up being thieves and hooligans within our community.

The IP Award has helped to personally spur me on with the project and the group of Blessed Pupils now numbers 30. The award also recognised BP as a global company dedicated to encouraging its employees to engage themselves in communities' social development. Most importantly, it highlights the fact that it is everyone's responsibility to make this world a better place for all.

**Delegates at the IP Awards 2003 raised £1,159.34 for The Hekima Orphans Foundation, which was subsequently matched by BP.*

Balancing supply with politics

A decade ago the energy industry viewed Brazil and India as key growth markets for gas-to-power projects. Both countries were, and remain, energy poor relative to their potential for economic growth. Ten years on, Brazil and India have taught the energy industry a series of unwelcome lessons on the legal and political pitfalls that such projects carry in their wake. *Maria Kielmas* reports.

The Brazilian President, Luiz Inácio Lula da Silva, is currently formulating a new gas policy – triggered by new gas discoveries in the offshore Santos Basin as well as gas and power shortages in the northeast of the country in late 2003/early 2004. This comes hot on the heels of the government's recently introduced electricity market model – which was given a cool reception by the energy sector – and most industry players expect further confusion in the market.

Access to energy supply

The Brazilian Government's fundamental goals on its election in 2001 were to protect the ability of low-income groups to have access to electricity (some 20mn of Brazil's 170mn population have no access to electricity) and to adopt a vertically integrated model for the power sector. Crucial to this was the relegation of gas-fired power from a priority to a marginal division. Some 90% of Brazil's electricity comes from hydroelectric power generated mostly from seven major river basins.

The previous government of President Fernando Henrique Cardoso had to rig the existing energy market in order to accommodate gas-fired power plants, whose fuel was imported from Bolivia. Power from gas-fired plants was scheduled to be dispatched first to the grid – but the high wholesale power prices this commanded, in order to finance the projects in the first place, were not used to set the overall market price. In addition, power distributors were faced with a cap on the prices that they could pass on to their customers.

Falling apart

This scheme fell apart by 2001 on the back of the high US dollar. Before its fall, the sector was hit hard by two years of drought during which wholesale spot power prices spiked 50-fold, and the inability of foreign investors to include dollar-linked price escalation clauses in their power purchase agreements (PPAs) with distributors. This meant that investors lost any incentive to continue with their projects. As a result, state oil company Petrobrás, which dominated the gas-to-power sector, had to write off

R$1.43bn ($503mn) in its 2003 accounts for losses due to the collapse of the gas-fired power programme. In early February this year the company announced that it expected this collapse to result in at least an annual $330mn 'bleeding' from its accounts up to 2007.

The discovery of over 14tn cf of gas in the offshore Santos Basin has prompted local politicians to call for a renewed effort to increase gas consumption in Brazil. The Sáo Paulo State Governor said he hoped that the new supplies could cut local gas prices from $3.30/mn Btu to below $2/mn Btu, and triple the present demand.

New market model

The Brazilian Government unveiled its new electricity market model in late 2003. In what could become a receipe for confusion, there will be two energy markets as a result – a regulated power pool, and an open market with a free price. The pool will group so-called 'old power' from amortised hydroelectricity plants, together with expensive power from gas-fired plants, in the hope that the combination will make the gas-fired product cheaper. The pool is to work on an auction system – it is still not clear what kind – and power will be sold to major distributors who will only be able to make purchases from the pool.

The free market will work on the basis of generators selling directly to large consumers and intermediaries who will negotiate their own contracts. There will also be a balancing mechanism.

The new set-up is similar to the present power market system in Poland. This provides a good deal for intermediaries to make money as advisers in energy risk management, but trading on own account is still difficult. Furthermore, the pool system in part works to entrench the status quo and the financial and political muscle of regional power generators. In Brazil these are usually state-owned or controlled. While such 'pork-barrelling' might assist the Lula government in any other political reforms, the introduction of gas, or any other new fuel, into the energy mix remains as difficult as ever.

Northeastern shortages

Power and water shortages in the northeast in late 2003 and early 2004 illustrated the inconsistencies in successive governments' energy policies. Reservoir levels were low, so hydroelectric plants could not operate. Petrobrás claimed that it could not supply gas to substitute gas-fired power plants in the region because an accident had cut back on gas production. The lack of gas transportation capacity meant that supplies from other sources could not be directed to the northeast. The construction of a gas pipeline to Ceará had been delayed because of problems with obtaining an environmental licence. Energy Minister Dilma Rouseff decried the situation of a 'hydroelectric power plant without water and a gas-fired plant without gas' and criticised the previous government for its lack of energy planning.

In early February 2004 the Petrobrás Board was split on the legal implications of a proposal to import cheaper gas from its own production in Bolivia, outside of the original Brazil–Bolivia gas supply contract which worked to finance the construction of the transportation pipeline between the countries. Meanwhile, Brazilian industry organisations gave the thumbs down to the new power model, stating that it will not provide a sufficient return on investments for a necessary 3,000 MW to 4,000 MW annual generating capacity expansion.

Dabhol sale

Elsewhere, in India, Finance Ministry officials in Maharashtra state are pushing to complete the bidding and sale of Enron's 65.15% stake in the Dabhol Power Company (DPC) ahead of state assembly elections in September this year. The state government is keen to restart the plant, which has been mothballed since 2001, because of severe local power shortages. But it first needs to negotiate a power purchase price from the plant that is acceptable to both low-income end-consumers as well as potential foreign investors.

The decade-long Dabhol saga does not provide encouraging pointers, while aspiring project financiers may find that their political risk insurers will be wary of the implications of an August 2003 US arbitration tribunal award in respect of the plant.

Biggest ever investment

The $2.9bn Dabhol project was to be the largest ever foreign investment in Indian history. Its two-phase project consisted of the construction of a power generation plant to run on LNG as well as fuel oil, while the second phase would be a regasification facility. The sole buyer for the power produced would be state-owned Maharashtra State Electricity Board (MSEB). The DPC and MSEB concluded a long-term power purchase agreement (PPA) in 1993, just one year after the original foreign investors (Enron (80%), Bechtel (10%) and General Electric (10%)) signed an original memorandum of understanding for the project with the then Congress-led state government. The agreement provided for international arbitration. The consortium also contracted an agreement with the Maharashtra Government, under which the latter would pay for any power for which the MSEB failed to pay and provided further guarantees with the Indian central government. In late 1998 Enron sold a 15% stake in the project to MSEB.

The election in March 1995 of a Hindu nationalist-led coalition as the government of Maharashtra state changed the political atmosphere. Indian opposition parties had been campaigning on an anti-Enron platform for almost a year. Their chief complaints were the speed with which the original contract had been signed and the high power price. The World Bank also concluded in 1993 that power prices were too high for Maharashtra state and that the Dabhol project was not viable. It did not finance the project.

In early 1994 the consortium sought, and was awarded, $635mn in financing, insurance and loan guarantees from the Bank of America, ABN Amro, a group of Indian banks, the US Export-Import Bank, and the US government agency Overseas Privatise Investment Corporation (OPIC). Enron was also seeking a long-term relationship with India in the hope that the country would become a major market for LNG imports from the Middle East. Enron would make earnings both as an intermediary and a gas buyer.

Agreements voided

The new Maharashtra Government set up a committee, the Munde Committee, to review the project. This, in turn, advised the project's cancellation. The state government followed this advice and, in 1995, filed a suit against the DPC consortium to void all agreements, alleging fraud and misrepresentation. But the consortium successfully co-opted both the Clinton administration and later the Bush administration to pressure the Indian Government on its behalf. In February 2002 a US House of Representatives report on the Dabhol project stated that: 'Secretaries of State, Treasury and Energy all supported the project, particularly during Enron's disputes with the Indian Government in 1995 and 2001.'

Legal challenges by Indian groups were dismissed periodically until December 2001, when the state of Maharashtra halted payments to DPC. The MSEB claimed to be short of funds, but offered a cheque for a smaller amount. The DPC returned MESB's cheque. The MSEB claimed the dispute could be resolved through mechanisms detailed in the PPA. But DPC called upon counter-guarantees from both the Maharashtra state and Indian central governments. The two governments did not accept DPC's claims, so the latter initially terminated the PPA. This termination was not approved by OPIC, which both guaranteed loans to the project and also provided political risk insurance. OPIC maintained that the consortium members should participate in an auction to sell the project's assets to Indian buyers. GE and Bechtel had serious reservations about this, but co-operated. However, Enron refused to co-operate and, as a result, OPIC threatened Enron with a denial of its claims against expropriation. But OPIC's decision not to approve a final termination of the PPA halted a possible opportunity for GE and Bechtel to sell their stake in Dabhol to the Maharashtra Government and thus recoup some of their investment.

Claims filed

The consortium filed claims against the MSEB for failure to pay for power purchases over the lifetime of the project, as well as claims against the state and federal governments, and OPIC. Some six international arbitration disputes were underway in respect of the project when a US arbitration tribunal in Washington awarded $28.57mn each to GE and Bechtel against OPIC. This award stunned political risk insurers and US lawyers because OPIC was obliged to compensate for something it had not underwritten in its original policy. This policy stated that OPIC would compensate its insureds in the case of non-payment of an award by an international arbitration tribunal in London, which was stipulated in the original PPA between DPC and MSEB.

But this arbitration was hindered by the Indian state authorities and essentially the tribunal was left to decide who – OPIC or Bechtel and GE – had to face the unforeseen risk that the Indian authorities would intervene in the contract between DPC and MSEB. The tribunal noted that 'from its inception... the project had been a political lightning rod' and that the consortium members were taken by surprise by the actions of the Indian Government agencies in breaching and making impractical the international arbitration procedures stipulated in the original contract. In addition, the claimant companies were prevented by OPIC from exercising their option to sell their stakes in the project to the Maharashtra state government.

Some lawyers interpreted this as the tribunal finding that the claimants could not be expected to bear the risk of OPIC protecting its own self-interest. Meanwhile, another legal opinion believes that the tribunal has ignored clear limiting language in the insurance contract and has allocated the unforeseen risk to the insurer. As the Maharashtra state authorities prepare to sell Dabhol once more, which insurers would be prepared to provide protection for future Dabhol financing?

OPIC stepped in once more. The US state political risk insurer paid an earlier claim of $63mn to GE and Bechtel before the $57mn arbitration award in August 2003. In addition, it has paid a similar political risk insurance claim of $28mn to Bank of America, on top of picking up Enron's remaining 65% stake in Dabhol for $22mn in payment to the Enron Creditor Committee. Enron is said to have invested $608mn in the project. OPIC also has $194mn of loans outstanding to DPC. It is also entitled to a 7% equity position in the project.

Will history repeat itself?

In late January 2004 media reports suggested that the foreign investors in Dabhol were prepared to sell their remaining stakes for one-third of their original investment. Potential buyers are thought to include an alliance between a unit of Indian conglomerate Tata and BP, with Shell, British Gas and India's Reliance Industries also mentioned. Investors in Indian, as well as Brazilian, gas-to-power projects can only hope that history will not repeat itself once more.

New thinking needed for exploration?

Consultant Wood Mackenzie has recently published the following briefing paper in its 'Horizons' series. In it *Matthieu Castellani*, Director – Strategy Consulting, and *Andrew Latham*, Principal Consultant, look at the very significant exploration challenges now facing the industry.

The death of exploration has been greatly exaggerated. Nevertheless, the oil industry now faces significant exploration challenges. Exploration, which has been the growth engine of the business, is maturing. Companies will need to face this reality and adjust exploration strategies or look to other business areas if they are to continue to grow. For the majors particularly, the exploration challenge is large and new thinking will be required for future winners.

From our global PathFinder database, we can summarise some of the recent trends in exploration. Since the mid-1990s:

- Global exploration has added value with average returns above 10%.
- Wildcat success rates have held steady at around 30%.
- However, since 2001 companies have not replaced reserves through exploration.
- The average value of discoveries has fallen.
- All the value has been created in deepwater. Exploration elsewhere has destroyed value overall (except Kashagan).
- Performance has been very patchy, with some good success, but with more than a third of the most active 25 companies destroying value.

We expect 2003 to emerge a strong year for booked reserves when the reporting season comes this spring. However, a lot of the reserves booked will be gas – often found decades ago and now being commercialised. This will flatter the explorers but disguise the real picture.

What's the future for exploration?

The 1990s saw major advances in the opening of exploration acreage to the international oil industry. Changing geo-politics and technology were the two principal drivers. Much of what became available – like deep water – was previously undrilled or at least had not been explored with modern techniques. Accordingly, the oil companies – which through the years have been very successful at identifying the big prospects early on – made very significant discoveries.

But life is now getting harder for the explorer. The amount of prospective new acreage being offered is shrinking. Finding the biggest prospects early on means that it is the smaller ones, in general, that remain. And these are less profitable than their bigger brothers as the gearing effect of size takes its toll. Technology has helped in defining the sub-surface better and in reducing costs to enable development of more challenging fields. But, as it has accelerated hydrocarbons discovery, it has also added to the future problem. There is no escaping the fact that oil and gas are finite resources – the more that have been found, the less that remain to be found.

Figure 1 shows the aggregate spending of the ten largest western majors, together with the net present value (NPV) of the discoveries they have made. After the good years of 1999 and 2000, there has been a steep fall in the value of oil and gas discovered. Note also that the aggregate spend level has not reverted to what it was before the mega-mergers.

Reserve replacement is a critical issue. A super-major like BP needs to add around 1.3bn barrels of oil equivalent (boe) each year – more than 100mn boe each month – to sustain its position. Between them western majors need to find the equivalent of an Angola every 15 months or a UK North Sea every 18 months just to stand still. And most want to do better than that – they want to grow.

Of course discoveries will continue to be made. Re-interpretation of mature basins will almost certainly produce some good surprises. Politics evolving and advances in technology could bring opportunities in regions that have not yet been explored. The Arctic National Wildlife Refuge (ANWR) and the arctic more generally could hold major reserves but do not seem likely to open in the medium term. New licences in places like the Nigeria-Sao Tome joint development zone (JDZ) offer potential, but not enough to sate the appetite of the industry for long. And the potential of some of the new countries that are being targeted (Benin, Mauritania, Kenya) remains uncertain and may not be large.

Two-thirds of recent discoveries have been in deep water. Our forthcoming syndicated study 'The Future of Deep Water' will present a view of the future potential of deep water in terms of both volumes and value.

In terms of reserve replacement, recent exploration results have been somewhat disappointing. Although many companies have been able to replace reserves in part by booking 'discoveries' through commercialising existing fields, the true amount of oil and gas actually being found is considerably less. This means that the inventory of known reserves that have not been developed is falling. It is only a matter of time until the discoveries booked under the SEC method must reflect this.

Figure 2 shows the total reserve additions of the ten largest western majors and contrasts their discoveries as reported in SEC filings with the reserves we believe they have actually found in each year. Although SEC filings have overstated what has actually been found in the last two years, many companies have done well through revisions by improving recovery from existing fields. Many also have inventories of discoveries that have yet to be commercialised – and, therefore, booked in the future. However, the bookings of recent years have depleted these inventories.

We believe that exploration cannot continue to be the main growth engine for the majors as it has in the past. Smaller companies with fewer reserves to replace and where a medium-size field could be a company-maker may view things differently. But the majors will have to find new ways to explore or find other ways to grow.

So, what are the options for successful exploration?

We believe explorers need to answer three key questions:

- What is our exploration for?
- How do we do the right things in formulating our exploration strategy?
- How do we do things right in implementing the strategy?

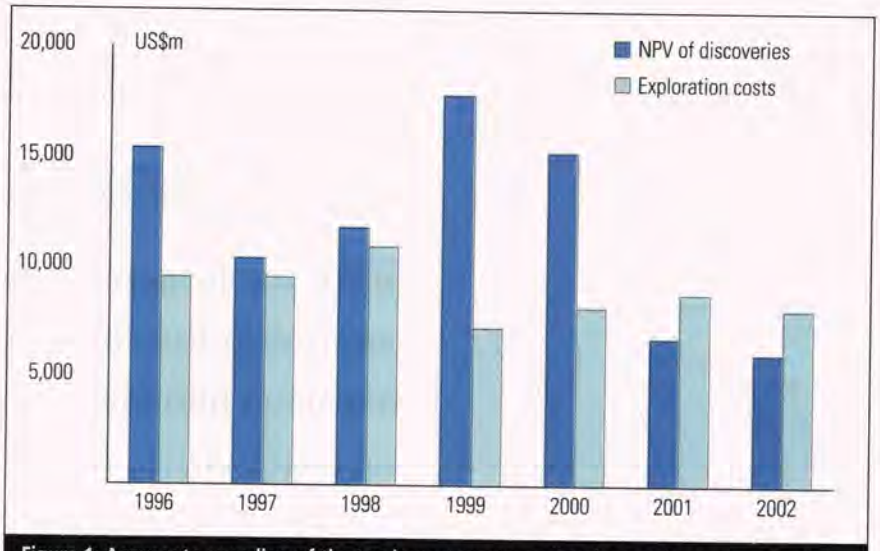

Figure 1: Aggregate spending of the ten largest western oil majors and net present value (NPV) of discoveries made *Source: Wood Mackenzie RADAR company annual reports*

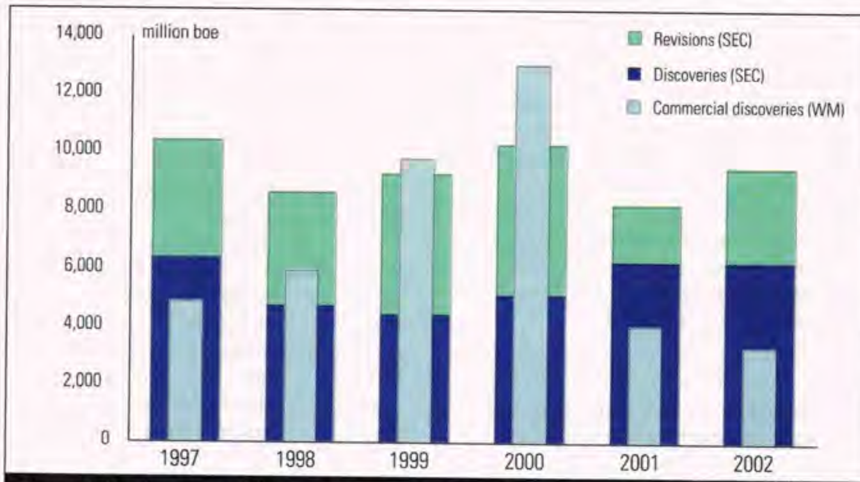

Figure 2: Total reserve additions of the ten largest western oil majors *Source: Wood Mackenzie RADAR company annual reports*

What is exploration for?

Finding the right answer to this question is critical. Successful companies must be clear about the role exploration plays in their growth strategy. Is it increasing reserves? Replacing production? Adding value? Discovering gas close to markets? Finding reserves that can be developed rapidly? The answer 'all of these' will not be sufficient. Companies need to set and share clear priorities if they are to be successful. In our recent syndicated study 'Value Creation Through Exploration' all the top performers had this clarity of purpose in exploration and senior management alignment about its role.

Doing the right things

As exploration gets more difficult, companies will have to review their strategies. Possible themes in terms of doing the 'right things' include:

- *Moving into new geographies.* The focus of exploration continues to move around the globe and several regions are currently enjoying renewed interest. Examples include many countries along the Atlantic margin of Africa (including Morocco, Mauritania, Senegal, Guinea-Bissau, Cote D'Ivoire, Ghana and others), the interior basins of Central Africa (Chad, Sudan, Niger), frontier Australia, and deepwater India, to name but a few. And explorers can also test fundamentally new plays without changing the geography – the deep gas plays of the Gulf of Mexico shelf or subsalt plays (Gulf of Mexico, Brazil) being examples.
- *Knowing when to stop.* Ultimately, exploration is not about adding volumes; it is about adding value. In 'Value Creation Through Exploration' we showed that most companies made money out of only a small number of the countries where they were active and lost money in the rest. It also showed that the area of greatest value destruction over the last five years has been the UK North Sea. So one of the lessons is to know when to stop – to be able to take the view that a particular region is just too mature. To withdraw completely from an area like the North Sea or parts of Latin America would be a tough call. This year, 2004, may not be the year to make it. The question for managements is: when will that time come? And how will they decide?
- *Be clear about the role of gas.* Gas demand is rising rapidly in many parts of the globe. There are already significant discovered reserves of gas that have no market yet. Companies that can combine effectively their exploration skills with excellent marketing and commercial skills will have an advantage.

Doing right things well

As well as doing the right thing, companies that succeed will do what they do well. Doing 'things right' could encompass:

- *Being more imaginative and creative in traditional areas.* In the last decade, as new and relatively prolific areas opened up and with a strong emphasis on cost reduction, many companies standardised their exploration processes and have seen talent go. With the new challenges of more mature exploration plays, new concepts must constantly need to be developed and explored. Companies need to find ways of re-emphasising creativity in their exploration process.

- *Dealing better with difficult issues like politics and the environment.* There are areas with known hydrocarbons that many companies choose to avoid either because of political difficulties or because of environmental concerns. Given the maturing of 'easier' regions, the industry should be spending more time and effort on working out how to deal with the problems of working in tougher environments.
- *Understanding how to work effectively with others.* In much of the upstream business companies act in partnership with others. Being clear how to select partners and how to work with them effectively will bring competitive advantage.
- *Being relentlessly value driven.* As basins mature and discovery sizes fall, unit costs will rise unless companies work the issue hard. Part of the answer may lie in evolving technology. Part may also rest with persuading host governments that the harsh fiscal terms of the best years need to be mellowed.
- *Improving the prediction accuracy.* Working to enhance the decision-making process and building better cases for exploration based on rigorous criteria will improve results. Within this, a thorough process of reviewing historical results and comparing them with predictions will improve future performance.
- *Being aggressive when new exploration acreage opens.* Companies need to be ready to move quickly when new exploration opportunities arise – identifying, selecting and ultimately accessing good acreage is key. And exploration can still deliver if new areas like the ANWR and Mexico open.

In addition to reviewing exploration strategies, companies need to develop other growth options. In particular, they must find ways to work profitably in areas with large reserves like Russia and the Middle East, monetise stranded gas and improve even further recovery from existing fields. Those companies that can solve the exploration dilemma, as well as finding other avenues for growth, will have the advantage.

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Interest stirs in the frontier's frontier

Since the disappointments of 1998 exploration, interest in the Falkland Islands' offshore waters has been minimal. However, interest is now reviving, writes *Maria Kielmas.*

Phyl Rendell, The Falkland Islands Government's Director of Mineral Resources, visited Barcelona last year and was pleasantly surprised. The exploration company executives attending the American Association of Petroleum Geologists (AAPG) convention in the city were showing a keen interest in Falkland Islands acreage. 'We had not encountered that kind of enthusiasm for high risk areas for some time and were quite heartened by the response,' she says.

The first exploration round resulted in the drilling in 1998 of six dry wells in the North Falklands Basin. Although the wells encountered a rich source rock and petroleum systems, industry interest waned. This was only to be expected as the Falklands is a hard sell – a frontier region a long way from any market. The Falklands Government always expected phases of industry interest. 'We've been pretty pragmatic about it, we knew we wouldn't get continuous activity,' Rendell adds.

In January Desire Petroleum began a 3D seismic survey over its C and D tranches in the Northern Falklands Basin. The company holds 100% of both blocks. Desire Chairman Colin Phipps says the survey will cost between $3mn and $4mn. The company is looking for traps below the thick Cretaceous source rock encountered in previous drilling. The survey will cover part of Tranche F, currently held by Talisman Energy. But the Canadian company has no plans as yet for its Falklands acreage, which it acquired in 2002 when it took over Lundin Petroleum.

Phipps thinks that the oil industry's current inertia regarding exploration actually works in favour of frontier area drilling. In 1998 semi-submersibles cost $130,000/d for work in the region. Today this rate is as low as $50,000/d or even less, he says.

Such lower rig costs would aid the Falklands Hydrocarbon Consortium, which holds 38,000 sq km of acreage in the South Falklands Basin. The Consortium comprises Australia's Global Petroleum (50%) and Hardman Resources (30%), together with a local Falkland Islands company that holds 20%. All sorts of play types such as large roll-overs, fault blocks, Tertiary channels and basin floor fans have been identified on existing seismic, says Derek Reeves, Global Petroleum's Business Development Manager. The Consortium has an obligation to shoot 3,500 km of 2D seismic over the coming 18 months. This is expected to cost between $2mn and $4mn. Reeves estimates that a well in the South Falklands Basin would cost about $7mn. The weather impact in the southern basin is no different to that in the northern basin. The main problem, he says, is the water depth, which ranges between 200 metres and 1,800 metres. 'But it wouldn't be a big deal if we had a number of wells to drill, and work was co-ordinated with exploration in the northern basin,' he says. The area's isolation is not so extreme. Most of the leads are located about 50km to 70km offshore, Reeves adds.

The increased activity offshore of southern Argentina is also encouraging for the Falklands prospects, Phyl Rendell thinks. Pan American Energy (which is owned 60% by BP and 40% by Argentina's Bridas) has just acquired a 35% stake in the West Malvinas Basin blocks 40 and 46. The company will be operator in block 46, with Repsol-YPF (34%) and Total (31%) as partners. Repsol-YPF is operator of block 40, holding 65%.

Talks between the Falklands Government, Britain and Argentina about the so-called 'joint area' to the southwest of the Falklands stopped two years ago. 'We agreed that until industry interest really focused on that area there was no point in continuing with the meetings. We need industry interest in it first,' she concludes.

Balancing a portfolio of low- and high-risk assets

As part of our series of feature articles analysing some of the smaller and intermediate oil and gas companies from around the world – based on information supplied by *Online-Data – we take a closer look at the activities of *Energy Africa*.**

Energy Africa is an African oil and gas exploration and production group listed on the Johannesburg and Luxembourg stock exchanges. The Group's primary objective is the enhancement of shareholder value and total return through growth in net asset value per share. Engen – a leading oil refining and marketing company in South Africa that is owned 80% by Petronas, the Malaysian national oil company, and 20% by Worldwide African Investment Holdings – holds 56.5% of the shares in Energy Africa. Petronas also directly owns 8.7% of the company.

Strategy for growth

Energy Africa's strategy for growth is to increase its hydrocarbon reserves and production through exploration, development and acquisition of projects principally in Africa. Since its flotation in 1996 the Group has successfully applied its technical knowledge, commercial experience and African identity to expand its interests into nine countries on the continent. In that time both reserves and production have increased more than threefold. (See **Figure 1**.)

The Group's working interest share of production for the year ended 31 March 2003 was 8.117mn barrels (2002: 7.823mn barrels) of oil and LPG – an average of 22,240 b/d and an increase of 4% over 2002 (21,430 b/d). New production was brought online in Gabon with the successful commissioning of the Etame and Niungo fields, whilst successful development wells contributed to production in the Echira, Moukouti and Tchatamba South fields.

Development plans were also progressed for the Okume, Oveng and Elon fields in Northern Block G (NBG) in Equatorial Guinea, where first production is expected in early 2005. Similarly, in Congo Brazzaville, development plans for the Moho-Bilondo fields have been submitted.

Higher production in the period to 31 March 2003 was accompanied by a significantly higher average oil price, which was further improved by a reduction in the company's average discount to Brent oil. This resulted in an increase of 24% in the average price realised from Energy Africa's production. Consequently, net cash inflow from operations increased by 32% to $126mn.

Exploration and appraisal

Fifteen exploration wells were completed in 2003, of which four yielded oil discoveries, one was suspended above the target interval due to mechanical problems and ten were unsuccessful (albeit that good oil shows were encountered in five of these). Three discoveries were made in Equatorial Guinea, where ten wells were drilled, whilst one successful well and three unsuccessful wells were drilled in Gabon. The well in Uganda was suspended.

Five appraisal wells – four in Equatorial Guinea and one in Namibia – were completed. The four in Equatorial Guinea were successful, but the Kudu-7 well in Namibia failed to increase the Group's reserve base.

At 31 March 2003, the net commercial (producing) oil and LPG reserves attributable to Energy Africa totalled 50.7mn barrels. This is a decrease of 7.2mn barrels (12.4%) from the 57.9mn barrels brought forward. The decrease was due to production of 8.1mn barrels offset by net revisions, extensions and discoveries.

Potentially commercial oil reserves totalled 42mn barrels, an increase of 4.7mn barrels (12.6%) over 2002.

Meanwhile, potentially commercial gas reserves increased from 210bn cf to 350bn cf (67%) as a result of an increase in the company's interest in the Kudu gas field in Namibia. While the gross technical reserves have not changed, these net economic reserves assume a smaller

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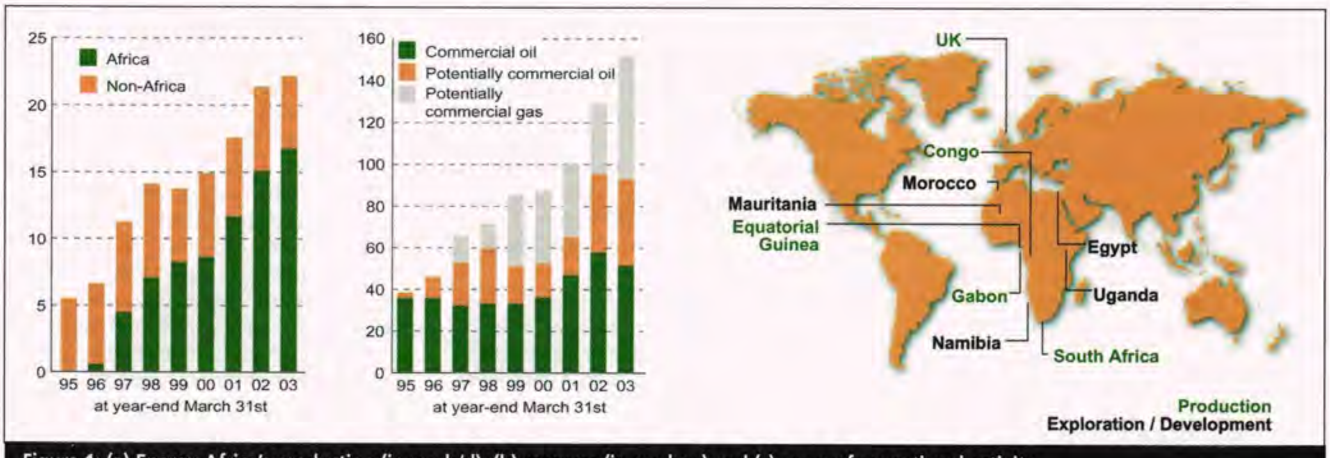

Figure 1: (a) Energy Africa's production (in mn b/d), (b) reserves (in mn boe) and (c) areas of operational activity

Small production heralds big future

Akita drilling rig

To date the production of gas hydrates has proved difficult and flows uncertain. Recent work by a international group seems set to change all that, reports *Gordon Cope.*

In March 2002, while Arctic winds howled around the drill site on the shores of the Beaufort Sea, a shallow production well tested almost 5,000 cf/d of natural gas.

Ordinarily this would hardly rate a sniffle in the oil and gas industry, where a production well typically produces 1mn cf/d – but this was no ordinary well. The gas being produced was coming from a reservoir of gas hydrate, a frozen mix of water, natural gas, mud and sand. They may look like small production numbers, admits Scott Dallimore, a Research Scientist at the Geological Survey of Canada and leader of the Mallik 2002 production and research well programme. 'This was a very small-scale controlled gas hydrate production experiment that represents a milestone in gas hydrate science,' he comments.

The excitement arises from the fact that this potential new source of energy is not only located in regions that are bereft of conventional hydrocarbons, like Japan, but also of a size that could dwarf proven reserves by many orders of magnitude.

Origins of reserves

Conventional natural gas reserves form when organic material trapped in sedimentary layers is broken down into simple carbon–hydrogen molecules through biogenic (bacteria-acting), or thermogenic (heat-acting) processes. The hydrocarbons – methane, ethane, propane and butane – migrate upwards until they eventually reach the surface and dissipate, or are trapped beneath impermeable layers of rock and form reservoirs. (Methane is the dominant gas as the others are likely to make up <1%.)

It wasn't until relatively recently that geoscientists encountered a third alternative. While drilling an exploration well in 1971, Imperial Oil penetrated a thick layer of cold, mushy sand beneath its Mallik lease in the Beaufort Sea. Intrigued, scientists began to study the chilly substance. Under certain pressure and temperature conditions water will form into a white, crystalline solid known as hydrate. While the material appears impermeable to the naked eye, it has an open structure at the molecular level. Typically, gases such as carbon dioxide and hydrogen sulphide are trapped within the latticework, forming gas hydrates. When a source of methane is present, it enters the lattice and creates methane hydrates – a potential energy source. A cubic foot of hydrate can hold an impressive 170 cf of methane.

Multi-phase lab studies show that hydrates form at lower temperatures and higher pressures than typically exist at the Earth's surface. For instance, methane gas hydrates will form at 0°C only if the pressure is 23 atmospheres. For hydrates to form at normal pressure, or 1 atm, the temperature must reach –80°C.

Ideal conditions for the formation of hydrates exist at the bottom of oceans and beneath the surface of continents, however. In the oceans, sea-bottom temperatures are in the 3–4°C range, and pressures in the region of 60 atm. Stable methane hydrates are found beneath the surface of the ocean floor when water depths exceed 300–500 metres.

In Arctic regions, where the ground remains permanently frozen to a depth of several hundred metres, hydrates are found at a depth of 500–1,000 metres. (Because the Earth's geothermal gradient rises by 3–5°C per 100 metre depth, the temperature of the ground becomes too hot to support hydrate structures below 1,000 metres depth.)

Dr Jekyll and Mr Hydrate

While there are many fundamental gas hydrate properties that can be studied in the lab environment, trying to create hydrate reservoirs under artificial conditions is frustrating. 'It's difficult to mimic real life conditions in the lab, in fact, it's almost impossible because there are so many variables,' says Dallimore.

Gas hydrates are also difficult to collect in the wild because of their instability under conventional drilling conditions. 'When the hydrate is in place, the reservoir is well consolidated, like concrete,' explains Dallimore. 'But when it dissociates (due to drilling mud invasion, say), it's like loose sand.'

Japan, which has no conventional petroleum reserves of its own, is keen to tap hydrates in its offshore basins. Since hydrates were already known to exist at the Mallik site, the Japan National Oil Corporation (JNOC) and the Geological Survey of Canada (GSC), together with others, undertook a C$10mn scientific expedition to the Mackenzie Delta at the edge of the Beaufort Sea. The objective was to drill and core hydrates safely and efficiently, and to use the data collected to advance chemical, physical and dynamic properties of the substance. The result was Mallik L-38, a 1,100 metre test well drilled in 1998. 'Scientifically, it was quite successful,' says Dallimore. 'We recovered the first, high quality well log data set, and honed our ability to do good coring work.'

The data greatly advanced scientific understanding of hydrates *in situ*, but critical knowledge regarding the exploitation of the reserves was lacking. Theoretically, it should be easy to produce gas from hydrates – by decreasing the pressure, increasing the temperature, or altering the reservoir chemistry by introducing a chemical. One of the simplest proposals for producing methane involves drilling through hydrates that form a cap above a conventional natural gas deposit, and removing the gas. As the gas is depleted, the hydrate cap depressurises, and the methane is slowly released downwards into the conventional deposit. Lab studies suggested that a frontal-sweep, steam injection pattern would allow significant production, but only if the reservoir had high, *in situ* permeability and a porosity of at least 15%. The thermal injection technique would require approximately 10% of the energy released to function successfully. The injection of a chemical, effectively dissolving the hydrate and releasing the gas *in situ*, was also a possible solution. Lab tests have shown methanol to be extremely effective in dissolving methane hydrates.

Hydrate core – gas hydrates within a granular sand from 920 metres depth
Photographs courtesy of the Geological Survey of Canada, Mallik 2002 Gas Hydrate Production Well Programme

In order to test out various methods of production, the GSC and JNOC established a wider partnership, including the US Geological Survey and US Department of Energy, GeoForschungsZentrum of Germany, the Gas Authority of India, BP Canada Energy, Chevron Canada Resources, Burlington Resources Canada, Imperial Oil and Schlumberger. A budget of C$17mn was set, and over 250 scientists invited to contribute to the effort. The plan was to drill three wells: – two observation wells and one production well.

Once again, Mallik was chosen as the test location. 'We went back to the same site because we had a lot of baseline information,' says Dallimore. 'We wanted to take a constrained R&D approach. We would learn from the information collected during the 1998 programme and advance our studies of reservoir and gas hydrate properties. However, we would also be much more ambitious as we wanted to undertake the first modern production testing of gas hydrates.'

Frosty reception

In November 2001 a collapsible drill rig with a 2,500-metre depth capacity was barged into position. After freeze-up, a road was built and support equipment sufficient to handle 90 scientists, drillers and support staff moved onto an ice-reinforced platform.

Drilling commenced 25 December, 2001, with the first of two, 1,200-metre observation wells. After their completion, the Mallik 5L-38 production well was spudded in late January. During most of the drilling the site was in total darkness, and the temperature would drop to –50°C. Paradoxically, special refrigeration units had to be installed to chill the drilling fluid. 'You have to heat the mud in order to mix it, then cool it in a controlled way to near 0°C,' explains Dallimore. 'We had to chill the mud because we had to stabilise the hydrates in the ground so that they wouldn't dissociate.'

The production well encountered hydrates between 900–1,107 metres. The team cored the 207-metre zone and shipped the material back to the Inuvik Research Center for evaluation and testing. The drillers then cased and logged the hole. In March 2002 the well was ready for the first-ever production test on a methane hydrate-bearing layer.

The problem was; which test? The scientists faced a time constraint – they had to finish their work before ice break-up made moving equipment impossible. Three test methods were possible – thermal, depressurisation and chemical. Three depressurisation experiments were run to examine the response of various gas hydrate intervals with different gas reservoir properties. Two other tests were then undertaken to look at the properties of non-hydrate sediments in contact with hydrate layers.

They began with a depressurisation test at the bottom of the hole. The hydrate zone itself was not one discrete unit, but a series of sand lenses separated by fine-grained silts. This created enough discontinuity that the scientists could treat different levels as though they were separate reservoirs. A 1-metre interval of the casing was perforated, then a special fluid collection tool lowered into place and the rest of the well bore sealed off. Fluid in the tool was evacuated, creating a partial vacuum that lowered the pressure within the reservoir and caused the hydrate to dissociate and flow into the tool. Several litres of reservoir fluid were captured for study.

The scientists then moved up to the top of the hydrate zone and placed a production test tool over a 13-metre section. The thermal test was conducted by circulating hot water across an area with open perforations. The gas, within the water, was then flowed to the surface, where it was separated and measured.

Over the following year, data from the field test were dissected and studied. The results were presented in December 2003, in Japan at an international gas hydrate symposium. Overall, the test proved that gas production from gas hydrates was technically feasible. Depressurisation produces more gas than simply heating, but a combination will produce the greatest amount of gas. 'The data also allows us to estimate permeability, saturation, thermodynamics and other properties with confidence,' comments Dallimore. 'We can plug these numbers into reservoir simulators and compare the results to our data set.'

The future

Before commercial exploitation can begin, however, more scientific work needs to be done. 'We're not at the point where we can launch a major gas hydrate production pilot,' says Dallimore. 'The next milestone will be a longer production test, one over several months. It will move past the near well-bore effects and test equilibrium response.'

Once again JNOC has taken a leadership position. At the moment, their five-year (2000–2005) research plan includes a polar onshore test scheduled for the winter of 2004/2005. When asked about this project, Dallimore commented: 'Certainly Mallik would be an ideal site for this test, but as far as I know the decision on the site has not been taken yet.'

When, and where, might the first, full-scale, commercial hydrate production occur? One clue is the amount of public money being invested. The Japanese spend over \$100mn/y, the USDOE around \$15mn/y and Canada about \$5mn/y. 'The Japanese have set offshore gas hydrate production as a goal,' explains Dallimore. 'They are now drilling 30 preliminary exploration wells.' MH21, Japan's long-range methane hydrate development plan, envisions production in the 2012–2016 time frame.

But money alone doesn't guarantee that the first commercial production will occur in Japanese waters. Offshore hydrate deposits are iffy, and the drilling and production challenges daunting. On the other hand, the Mallik deposit is well documented, the technology proven, and the site coincident to a major gas deposit that would be tapped to fill the proposed Mackenzie Valley pipeline. Conceivably, the hydrate zone could be exploited in conjunction with the conventional reservoir.

Eventually, however, gas hydrate production might be ubiquitous, thanks to its wide dispersal. The US Geological Survey reckons there are 700,000tn cf of methane in gas hydrates worldwide, which would potentially exceed the combined international reserves of conventional oil and gas, coal and oil shale.

Dallimore, however, recommends caution when dealing with such estimates. 'It's like assessing how much carbon is in sediments worldwide. The estimates for gas hydrates are widely dispersed, and mean nothing economically. There has been very little work done in terms of a petroleum system approach.'

Thanks to the research programmes, the Mallik site is the only gas hydrate deposit that has been delineated by geological constraints and engineering data. 'It's a coarse-grained sand in an anticline, so there are thermal, lithological and structural controls to the reservoir,' says Dallimore. 'We estimate reserves at 3.7tn cf.'

And although the Japanese programme may prove them wrong, existing data shows that the best known reservoirs are still concentrated in the Arctic. When the oil industry finally does get a good handle on gas hydrates, exploitable reserves may well be within an order of magnitude of known conventional supplies, currently estimated at 5,000tn cf.

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project than previously envisaged.

During the year, Energy Africa continued with efforts to expand its asset portfolio with a view to maximizing prospects of increasing net asset value per share. In this regard, the objective is to have a balanced portfolio of low- and high-risk assets, biased in favour of those offering higher reward potential. While Africa remains a key focus area in pursuing this objective, the company is nevertheless actively seeking participation in exploration ventures in the UK Continental Shelf as attractive opportunities emerge.

Recent company highlights

Early in 2004, Energy Africa concluded an agreement with Maurel & Prom, a French company listed on the Paris stock exchange, to acquire an 11% interest in the M'Boundi production permit onshore Congo (Brazzaville) for \$50mn in cash. The company said that, in addition, a cash royalty of \$1.50/b would be payable in the event that gross production from the permit exceeds 140mn barrels.

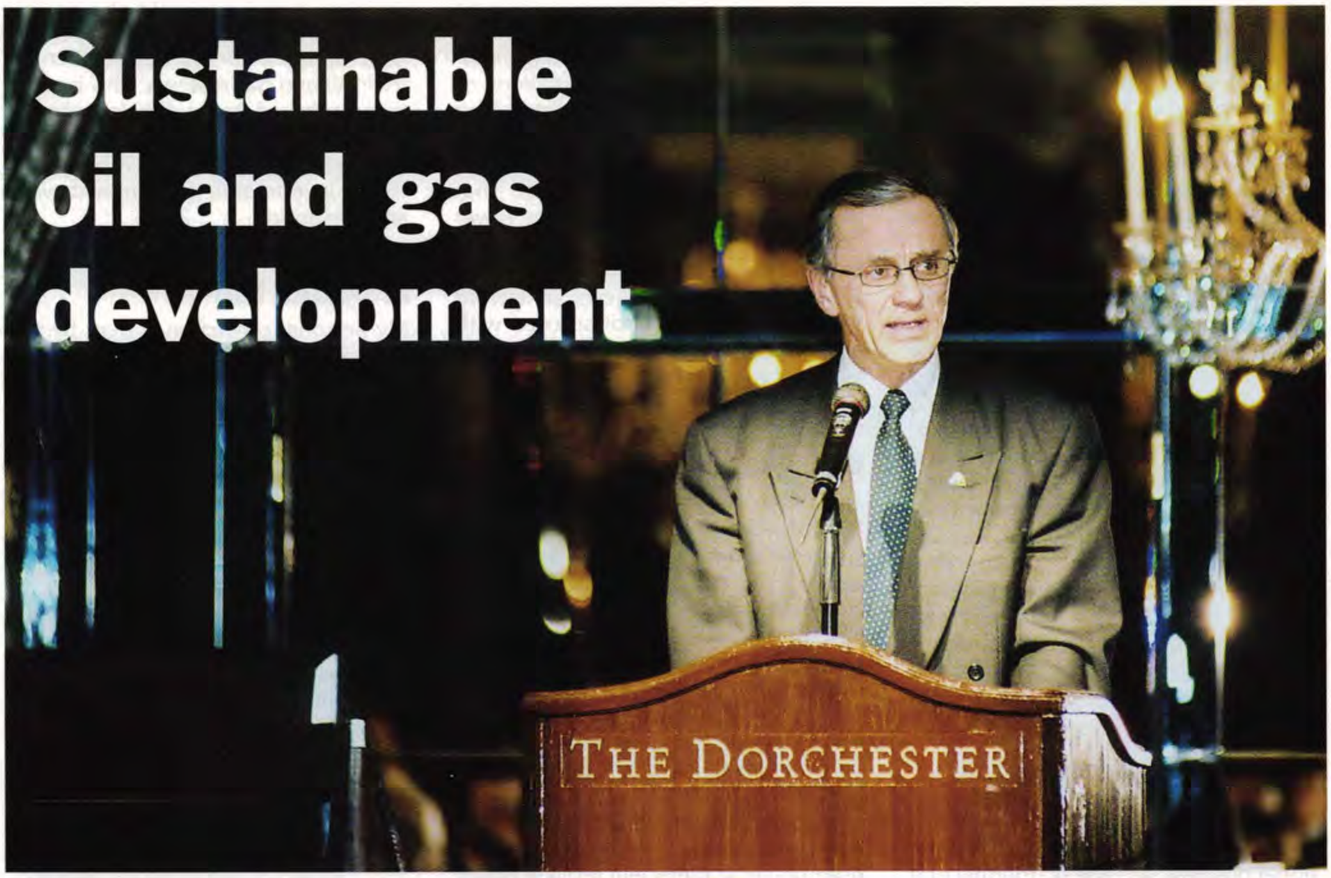
The Mboundi oil field came onstream in 2002 and was producing approximately 9,500 b/d of oil by year-end. According to Energy Africa this level of production is expected to increase substantially in 2004.

In December 2003, ChevronTexaco confirmed its intension to withdraw from the Kudu gas field project in block 2814A offshore Namibia. However, while the project may not fit into ChevronTexaco's strategy in West Africa, it remains a very important field for Energy Africa. The company remains very positive about the future of the project and is committed to continuing discussions with various stakeholders with the objective of making a decision on field development early this year. These discussions have already reached an advanced stage and Energy Africa intends to exercise its option to assume 100% interest and operatorship of Kudu.

North Sea licence awards

In August 2003 Energy Africa was awarded, through its wholly owned subsidiary Unilon Oil Explorations, interests in six 'Promote' blocks and in one traditional licence in the 21st Seaward Licensing Round on the UK Continental Shelf.

In partnership with Kerr-McGee, Unilon was awarded a 50% interest in block 16/13b, which is located immediately north of block 16/13d in which Unilon earned a 20% interest following the drilling of an exploration well in September 2003. In the newly instituted 'Promote' category of licences, which have an initial two-year period for geological and geophysical interpretation, Unilon was awarded interests in six blocks constituting four contiguous areas. These are blocks 211/17, 211/23d and 28b, 211/24c and 3/5 and 10c located in the East Shetland Basin.



Sustainable oil and gas development

Addressing the IP Week Annual Lunch at the Dorchester Hotel, London, *Inge K Hansen*, Acting President and CEO of Statoil, looked at the complex issues involved in sustainable oil and gas development.

Above: Inge K Hansen, Acting President and CEO, Statoil, and EI Guest of Honour
All IP Lunch photos: Jim Four

Sustainability, as I see it, is about performance and impact – performance according to the triple bottom line and impact on the environment and society. Sustainability is about the way we conduct our business. But are we able to combine strong financial and environmental performance with socially responsible behaviour? Is 'sustainable oil and gas development' a contradiction in terms or a realistic ambition?

The economic impact of our activities is often assumed to be the same as our financial performance – but there are significant differences. Finance concerns the market valuation of transactions that pass through a company's books. Economics, on the other hand, is the means by which society combines human and natural resources in the pursuit of human welfare. Economics extends far beyond the boundaries of a single company and is inextricably linked to both environmental and social elements of sustainable development.

Growing awareness

The world's awareness of environmental challenges, and the need for sustainable development, have changed dramatically during the last 30 years. In the 1970s environmental issues were largely a local concern. In Norway they were about our responsibility for marine life – the relation between oil production and fishing interests. They were about emergency measures for cleaning up oil spills – technology to recover oil from the sea. Norwegians would simply not accept seashores and seabirds fouled by oil. The environmental issues were about two important national industries that had to live cheek-by-jowl.

As the 1980s progressed it came increasingly clear that the environment was not simply a local concern. Global interdependency became ever more visible. The Brundtland Commission was symptomatic of, and in many ways heralded, a change of era. Attention was no longer focused solely on environment-related issues. The Brundtland Commission's final report – 'Our Common Future' – established an important connection between environment and development. It discussed the significance of the 'three Es' – energy, environment and economy – and the connections between them.

Poverty and energy demand

Poverty is a challenge facing all international business. As I speak, roughly one and a half billion people lack access to modern forms of energy. Nor have developments over the past decade been uniformly positive. Today, fewer people in Africa have access to a minimum electricity supply than 10 years ago. Over the same period we have seen a significant increase in the world's overall energy consumption.

Energy demand in the industrialised part of the world is expected to increase by a further 30% towards 2020, even with extensive energy saving. Fortunately, energy consumption in developing countries is expected to increase even more rapidly – estimates suggest a doubling towards 2020. Experts believe that this development will cause a rise in global emissions of carbon dioxide by almost 50% over the same period. Most of this expansion will derive from rising transport demand in developing countries.

People in populous developing nations and emerging economies naturally want the same access to, for example, transportation that we in the western world enjoy – and they expect that. What right do we have to tell this part of the world that public transport and energy saving represents the only path?

Former Indian Prime Minister Indira Gandhi said that poverty is the greatest polluter. Poor people cannot take account of the environment when their survival is at stake. As a result, the real challenge of our time is to achieve positive development for the millions of people who live in poverty. This involves helping to ensure that the poorest can take care of their own health, that children survive so that their parents can choose to have fewer offspring, and that they receive an education that enables them to contribute to the growth and development of their society. We cannot succeed with any of this unless the energy sector is assigned a central position.

Oil, gas and alternatives

Fossil fuels currently account for about 90% of world energy consumption, and will remain the dominant global energy carriers for many decades to come. However, the composition of demand is changing, and what we observe is a growing preference for natural gas. Demand for natural gas has outpaced other energy carriers in recent decades, and this trend is also likely to continue over the next 20 years. Most people regard natural gas as a 'clean' energy carrier, and a transition from coal-fired electricity generation to modern gas-fired power stations will provide major environmental benefits in the form of reduced carbon dioxide emissions.

Nevertheless, the oil and gas business is taking specific steps to develop alternative energy sources. But, at present, no magic formula exists which can replace fossil fuels at a stroke with renewable emission-free energy sources. And, most forecasts indicate that renewable energy is unlikely to play a bigger role in overall consumption 20 years from now than it does today.

Some people seem to believe that the environmental and climatic challenges signal the end of the petroleum sector's role and significance. I personally believe that this is wrong. A more relevant conclusion is that our common ability to meet these challenges will depend on our ability to take innovative approaches to both new and traditional energy carriers.

The income the oil and gas industry generates for people and society bestows an enormous potential for good. We provide energy that the world needs. Without it, there would be no development. And without economic growth, we cannot overcome the problem of global poverty.

At the same time, the income we generate also provides temptations for abuse. Sometimes we observe that not all the economic and social impacts of oil and gas are favourable. Some nations, regions and communities have not benefited as they should, or could have done, from the development of their oil and gas reserves. This is sometimes referred to as the 'paradox of plenty', when the potential benefits of oil riches are squandered through inefficient investments, government waste and corruption.

A better life

My personal conviction is that, by running our business as profitably and efficiently as possible, we can help give people in our host communities a better life. Our most important contribution is measured in terms of value creation – the impact of our investments on employment, procurement of goods and services, transfer of technology and expertise, and tax revenues. These spin-offs have multiplier effects, all of which help generate local growth and development.

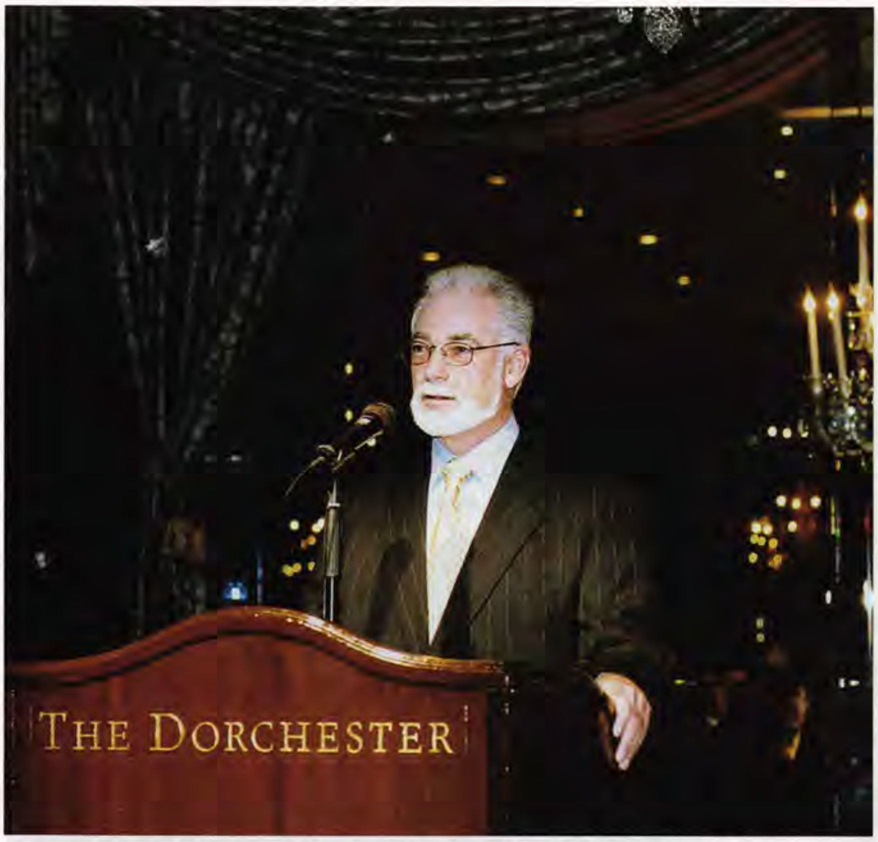
In coming years we will therefore need oil and gas companies which make technological advances in reducing emissions from fossil fuels. We need oil and gas companies that continue developing the cleanest energy sources, and reduce the use of the most harmful. And we need an energy sector that can develop renewables on a commercial and industrial scale.

In addition, I think we need to connect companies, governments, communities and non-governmental organisations (NGOs) in new partnerships. A commercial player should be careful about adopting a role or a responsibility that belongs more appropriately to national authorities, international institutions or voluntary organisations. Success will only come through partnerships that combine our different knowledge and separate strengths.

Statoil's experience

Statoil's experience has been shaped through the development of a new industry based on Norway's offshore resources. Our company was initially established as a state-owned oil company with strong industrial policy overtones. We were an instrument – and we were given a national assignment. Our culture is still coloured by that history. Our employees are proud of our past.

Statoil's biggest strategic challenge in coming years will be to transfer activities and production to new oil and gas provinces outside Norway as production from the Norwegian Continental Shelf levels off. The big question in this context is whether we can retain our



Brian Hamilton, EI Vice President, speaking at the IP Week Annual Lunch

distinctive character in the wider world and turn it into a competitive advantage. We have a good corporate culture, we have a solid expertise base and we have world-class technological solutions. Combined with our role in social development as a national oil company, this gives us a special position in competitive terms.

Our international commitment also presents us with new technical, commercial and – not least – cultural challenges. Resource-rich countries are often very different from Norway. But regardless of where we work around the world, we will operate profitably, safely and to high ethical standards. At the same time we will protect the environment and demonstrate social responsibility.

The significance of human activity for global warming can no longer be ignored. Strong action is therefore needed to reduce greenhouse gas emissions. Many people believe that the oil and gas industry was far too late in acknowledging climate issues, and that the adopted measures have been inadequate. I have some sympathy with this impatience, but strongly disagree with those who claim that we are doing nothing. Over the past few years Statoil has developed new solutions which will reduce carbon dioxide emissions. In this connection, the production from the Norwegian Continental Shelf is among the most energy efficient in the world. According to the International Association of Oil and Gas Producers (OGP), the industry's global average of carbon dioxide emissions is currently about 16 kg/boe produced. The corresponding figure for the Norwegian Continental Shelf is about 6 kg. On some of our new developments, emissions are as low as 2.4 kg.

Statoil is committed to observing and promoting fundamental standards for human rights. As an example, Statoil Venezuela has been sponsoring a human rights project since 1999, which aims to train Venezuelan judges in human rights – a joint effort between the UN Development Programme, Amnesty International, Venezuela's central Escuela Judical and ourselves. This scheme provides an interesting example of cooperation between an international organisation, an NGO, a government authority and a business corporation. It has allowed us to participate actively in a development programme that contributes at a local, regional and national level. The ultimate aim of the training is to help enhance awareness and professionalism in the judicial system, and to create a force against human rights abuse.

For Statoil, transparency and dialogue are vital. In the Norwegian business community, stakeholder dialogue is a traditional tool and has developed into a fundamental form of communication for Statoil, in Norway and internationally, at a corporate level and in relation to specific projects. This provides us with an in-depth understanding of how our activities are influenced by local communities, and how we influence the society in which we do business.

Our own Horton affair last autumn reminds us of the importance of transparency and compliance with company policies. This episode had dramatic consequences for Statoil, both internally and externally. It's a sad story, but our core values will prevail. We remain committed to conducting business in a manner that is ethical, economically viable, environmentally sound and socially responsible.

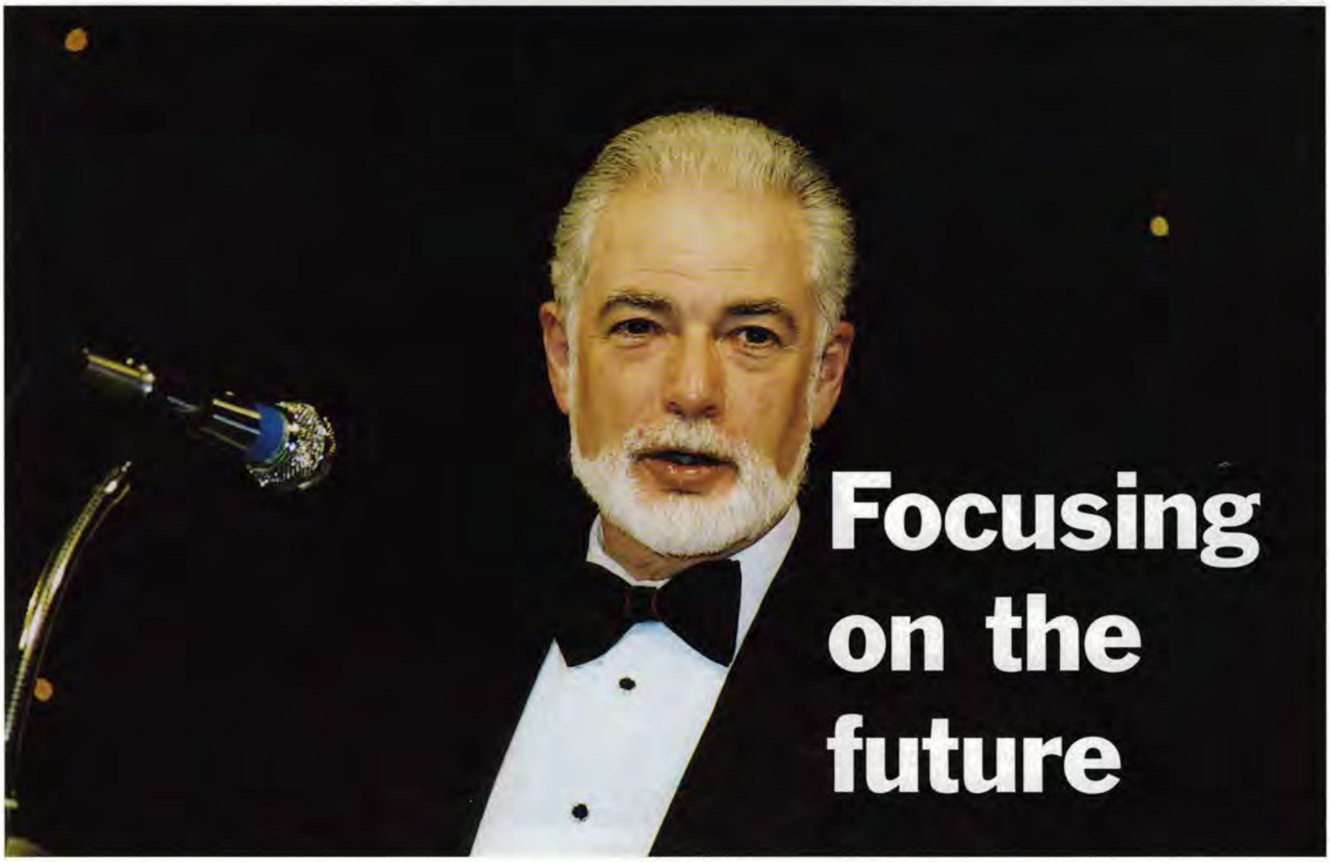
Performance and responsibility

At the beginning of my speech I raised the question 'Are we able to combine strong financial and environmental performance with socially responsible behaviour?' My answer is clearly 'Yes'. There are no alternatives. We all share the responsibility for our common future. For Statoil, sustainable oil and gas development is a definite and realistic ambition.

Earning the right to grow requires a licence to operate. Such a licence depends on both access and acceptance. Access is the formal licence or concession granted by governments. Acceptance is the informal or social licence granted by societies. Acceptance, or lack thereof, is based on stakeholders' assessment of our performance. Acceptance rests on perceptions of benefits versus costs. Generally speaking, our ability to do business will be limited unless we can demonstrate that our presence, especially in poor countries and emerging economies, is a source of human progress – in other words, contributes to sustainable development.

No place to hide

Some dismiss our statement of corporate responsibility and contribution to sustainable development as 'cheap window dressing', aimed more at changing perceptions than at improving reality. But any gap between words and deeds is not sustainable. There is no place to hide in today's interconnected world. A good reputation can only be created and maintained by results. Companies must walk the talk – and so must we as leaders.



Focusing on the future

Addressing the IP Week Annual Dinner at the Grosvenor House Hotel, London, *Brian Hamilton*, Vice President of the Energy Institute and Manager – Europe Gas Marketing, ExxonMobil, reviewed the current state of the oil and gas market and outlined some industry concerns regarding the UK Government's recently published draft National Allocation Plan for emissions trading. He concluded with a review of three of the Energy Institute's key initiative areas.

Above: Brian Hamilton addressing the guests at the 90th IP Week Annual Dinner; and right: proposing the toasts
All IP Dinner photos: Jim Four

For some while now there's been a sorry tale to tell about the downstream sector. We've seen very low margins – reflecting the combined impact of worldwide excess refining capacity, depressed growth in product demand and generally rising crude oil prices. In the UK, I'm pleased to say that 2003 was a slightly better year in the area of fuels retailing, where there was at last some improvement in margins – though not yet to acceptable levels.

The industry's contribution to reducing automotive emissions has been immense. We've completed the second stage of the Auto Oil air quality programme, and last year saw a start on the third stage, as well as preparation for the introduction of sulphur-free fuels this year. Having done a lot to reduce vehicle emissions, the emphasis is now on reducing vehicle fuel consumption and subsequent carbon dioxide (CO_2) emissions.

Turning to the upstream, 2003 showed attention focusing more and more on new opportunities in areas such as West Africa, the Caspian, Eastern Canada, the Middle East, Russia and the Gulf of Mexico. Worldwide demand for oil and gas is forecast to increase by some 40% by 2020 so we need to develop energy supplies – both to meet new demand and to replace supplies from maturing resources. In just ten years' time we are likely to need

an additional 100mn boe/d. Developing reliable, affordable supplies will be an enormous challenge.

Good news, bad news

The good news from the North Sea was that production last year was only fractionally lower than in 2002, and around £3.4bn was invested in new facilities, developments and drilling. The not-so-good news is that UKOOA's 2003 activity survey shows that although we have around 30bn boe still to be produced, there are only development plans for around half of this out to 2030. Drilling levels remain historically low and, as prospects become smaller and more risky, extraction of those remaining barrels will be increasingly difficult. Together with government, we need to address this urgently if the North Sea is to remain competitive against developing provinces.

Forecasters agree that the UK is on the threshold of becoming a significant importer of natural gas. By the middle of the next decade it is likely imports will be needed to meet around two-thirds of UK natural gas supplies. New pipeline supplies such as those committed from Norway's Ormen Lange field are important, but the exciting new development is the proposal to bring LNG to our shores, adding significantly to UK natural gas supply diversity and security.

Over recent months deals have been announced involving ExxonMobil and Qatar Petroleum using a site at Milford Haven; British Gas International and Petronas of Malaysia at Petroplus' Milford Haven facility; and BP and Sonatrach of Algeria at Transco's Isle of Grain facility. All represent the entry into the UK market of new players, new technology and new infrastructure development. From my own experience, UK Government and regulators have been extremely active in facilitating the development of these projects. We all look for a similar level of support as the European Commission (EC) begins to consider applications for exemption from the provisions of the Second Gas Directive in regard to these projects.

Emissions trading

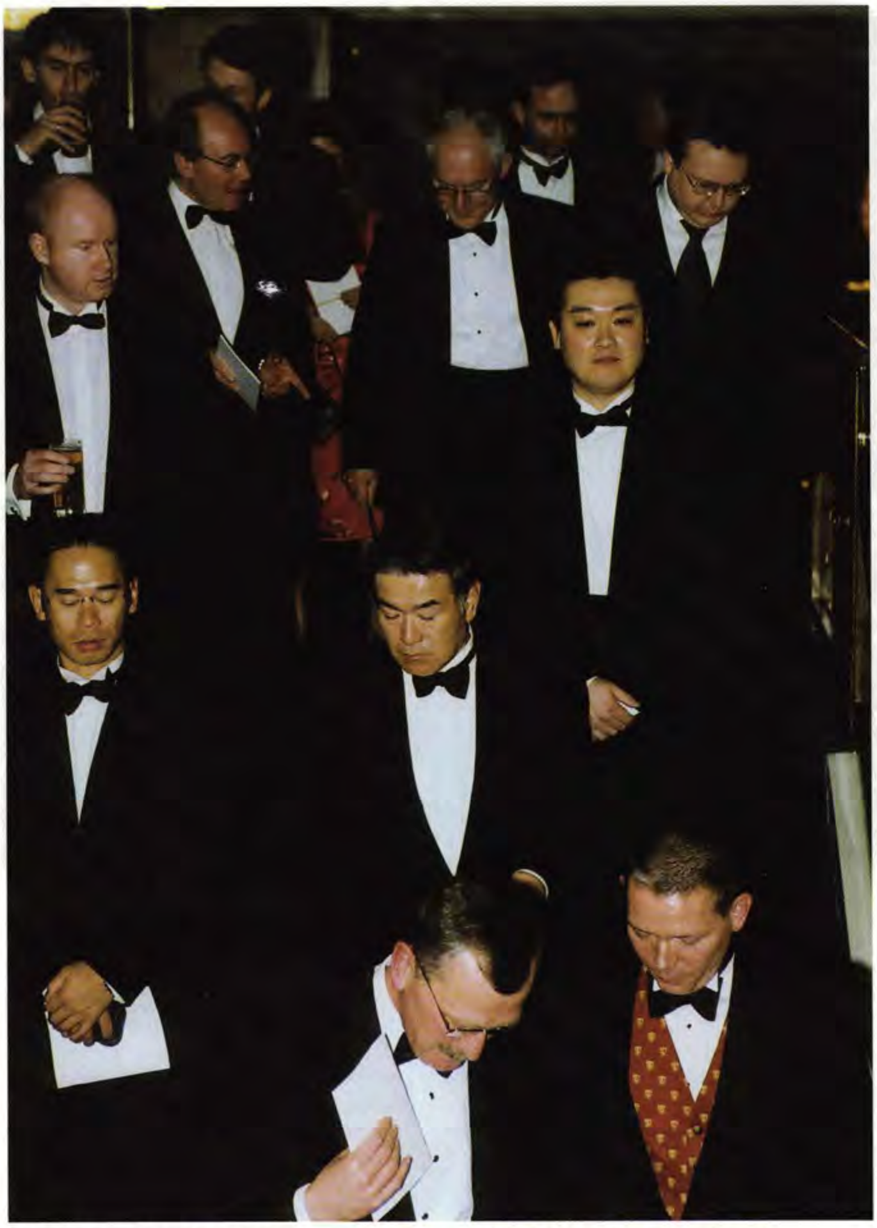
Turning now to an issue that came to a head during 2003 – and it's one that is of huge importance for all aspects of the energy business right across Europe. I'm referring to CO_2 emissions trading. In setting a start date of 1 January 2005 for the first implementation period, the EC has set a challenging target – a target which member states' governments will find some difficulty adhering to.

The UK Government recently published its draft National Allocation Plan [see this issue, p7]. But the vast majority of industry was disappointed to see the UK being committed to setting an overall target for the traded sector which takes the UK significantly beyond its Kyoto Protocol obligations – an ambition not shared by the majority of EU Member States. Trade associations covering the upstream and downstream sectors have already expressed their concern that in the government's haste to publish numbers, accuracy may have been sacrificed. The current proposals for a cap on the upstream around 40% below the baseline does not chime with government goals of maximising UK Continental Shelf production to help meet the energy security policy goals outlined in the White Paper. And in the refining sector, we await government advice on just how they are going to handle the requirement to produce zero-sulphur fuels, which will increase refinery CO_2 emissions.

We trust the UK Government will watch the publication of other draft National Allocation Plans as closely as the industry will – to ensure that the competitiveness of UK-based players is not adversely impacted.

EI intellectual reservoir

Now, having got that off my chest, I will return to the Institute. Our new Energy Institute (EI) aims to be an intellectual reservoir for the industry, building on the strong heritage of its founding



Above: Guests make their way down the main staircase to the Great Room, Grosvenor House Hotel, London. Below: Brian Hamilton (right) chats to Guest of Honour and Speaker, John Simpson CBE, BBC World Affairs Editor

bodies and the undoubted base of expertise provided by the members around the world. Tonight, I am going to cover just three of the Institute's key initiative areas – education, technical excellence and recognition of the industry's contribution.

First, education. Over the last year we have heard much on the subject of skill shortages and low graduate intakes. The new Energy Institute is in a position to start solving these problems. At schools and colleges, for instance, the Internet is being utilised with the provision of interactive learning aids, and we thank our industry partners for their ongoing support of these programmes. At universities, both in the UK and increasingly overseas, we are working to build professionally accredited courses. Graduates will be guided along the path of professional recognition, which could lead to their qualification as Chartered Petroleum Engineers. The EI will be supporting all those interested in energy throughout their careers, and will be working with companies to deliver continuing professional development, either through its own courses or by accrediting in-house training schemes.

Secondly, on the technical front, last year the companies involved in the EI's scientific and technical programme decided to undertake a piece of work to establish the value to the oil and gas industry of projects carried out by the Institute. The results make interesting reading. Over a two-year period the Institute returned a value of over £42mn to the UK industry, from an investment of under £2mn. It is also worth noting that the Institute's work can be considered truly international, with many of the industry's standards and codes of practice in day-to-day use in over 70 countries around the world.

This year, 2004, sees the launch of a new category of membership – Technical Group Member. This will allow smaller companies to start actively participating in the technical work undertaken by the Institute on behalf of industry, ensuring that, as the Institute moves forward, its work and membership are fully representative of the ever-expanding energy sector.

Third, and finally, there is the area of ensuring that the industry is recognised for the contribution it makes to society through the annual EI Awards. Last year saw the most successful awards ceremony to date, with entrants from all around the globe and contributions both on a corporate and an individual scale. The EI Awards represent an ideal means by which companies, large or small, can shout to the world about their achievements. But, as ever, if you don't enter you won't be able to win!

The first day of IP Week 2004 concluded with a reception for delegates at the House of Commons hosted by Philip Hammond, MP

Top: John Brooks, CBE, FEI
Above: Matt Simmons, Chairman, Simmons & Company International

Highlights from day one

Petroleum Review Editor *Chris Skrebowski* briefly reviews some of the highlights during IP Week 2004.

Delegates were welcomed to the Peter Ellis Jones Memorial Day talks that opened IP Week by John Brooks CBE, Chairman of the 'Price Sustainability – Economics and Energy Supply' conference. Introducing the first speaker, he noted that this was to be the first IP Week organised by the recently formed Energy Institute.

Matt Simmons, the Houston-based Energy Banker, was the first speaker at the well-attended Peter Ellis Jones memorial day that opened IP Week on Monday 16 February. He addressed the topic of economics and energy supply with a series of robust challenges to the conventional wisdom of the industry. His talk, entitled 'Current sources – a global view', started with his statement of the conventional views of the industry – that supply was growing, prices were tending to decline and that gas was assuming a greater role. An essentially benign situation in which prices weakened. He commented that oil supply had already reached 80mn b/d, and possibly as much as 82mn b/d, while gas accounted for a further 45mn boe/d. He also noted that the industry was already a \$1.5–\$2tn/y business and, if you included the directly associated electricity generation, it was already a \$3tn/y business.

However, he continued, the conventional wisdom was always wrong and he maintained we were now moving into a new era. Already, finding costs have doubled in the last few years and production growth was becoming more difficult. The US gas supply industry appeared to have entered an era of permanent decline. Demand appeared robust and mild weather in the US and elsewhere had helped to avoid a supply pinch, although rapid expansion of European diesel demand was already distorting refining patterns and leading Europe to become a net importer of diesel.

Turning to the supply side, he mentioned the lack of gas supply in North America and the freely available supplies in much of the world. He outlined the situation in China and Mexico, both of which are attempting to expand gas supply to meet rapid demand growth.

Noting the world's dependence on a limited number of old giant fields, Simmons quoted the statistic that 14% of the world's oil supply (nearly 12mn b/d) came from just 14 old, giant fields. Yet, despite this obvious vulnerability, drilling activity continued to contract. Commenting that another conventional wisdom had been that US gasoline demand was locked in the 7–8mn b/d range, he pointed out that current growth in the sales of fuel-inefficient vehicles such as SUVs meant that US gasoline demand was now approaching 9mn b/d (or 11% of global oil demand).

He explained that the apparent good news of rapid Russian production was, in fact, the vigorous exploitation of the oil left behind. Rapid exploitation of this was the result of the very high effective yield as a consequence of the rouble devaluation. A yield he estimated to be equivalent to \$100/b oil.

Simmons also discussed the potential vulnerability arising from the fact that 90% of Saudi oil comes from just eight mature fields. Already the Kingdom is drilling only horizontal development wells in an effort to maintain production flows.

He then went on to develop the idea that prices for the industry's products were too low to sustain the sector. He noted that a recent IEA study had found that \$16tn needed to be invested in all aspects of the industry if it was to meet future demand. He elaborated by illustrating the way many of the industry's problems would be minimised or disappear if prices were higher. Low prices were the reason capital had fled the industry and only higher prices would

Top: Andy Inglis, Group Vice President – Upstream Business BP
Above: Kieron McFadyen, Technical Director, EP Europe, Shell

Matt Simmons chats to Paul Tempest, CEO, Windsor Energy

generate the capital flows to regenerate the sector. Having challenged much of the industry's conventional wisdom, Simmons concluded with the somewhat cryptic question: 'What is the prudent sustainable capacity for Saudi Arabia?'

Entering a new era

Andy Inglis, Group Vice President – Upstream Business, BP, in a strongly upbeat presentation, told the audience that BP was entering a new era in which it was creating a series of new businesses focused on low cost areas of production. He described this as a four-stage process – creating a business, building it up, producing it and then harvesting the output – always remembering the importance of the cut-off point, when an area should be exited.

He claimed that BP currently has the lowest finding costs, at $0.91/boe, and a reserves replacement of 119%. He stated that the company with the 'best rocks' wins; giving the audience the clear impression he believed this to be BP. He noted that geopolitics presented companies with high risks but, for those who succeeded, high rewards. The opening of the FSU states such as Azerbaijan had opened up possibilities that BP has seized and enabled them to offer mutual advantage via the shared benefits of the field developments. The full benefits of the 5bn barrel Azeri-Chirag-Guneshli development were building up and would really flow once the Baku-Tblisi-Ceyhan (BTC) pipeline was completed in 2005. Similarly, the benefits of the 3tn cf Shakh Deniz gas discovery would emerge once the pipeline was completed in 2006. He stressed the secret of success was working closely with the locals.

For BP, Russia presented a very exciting challenge. Inglis said that BP 'knows Russia very well', having sent teams there in 1989 and taking an initial 10% holding in Sidanco in 1997. The early learnings had culminated in the TNK-BP merger in early 2003, which on the SPE definition gave BP access to 10bn boe of proved reserves, 17bn boe of proved and probable (including Ryalchik, the lower producing horizon at Samatlor) and up to 31bn boe of 3P reserves – and this before any further exploration. New seismic technology was opening up subsalt resources – notably in the Gulf of Mexico. A region where 13bn barrels of reserves had already been found – a figure Inglis expected to rise to 30–40bn barrels, with most of the increment coming from subsalt areas.

Inglis explained that BP was focusing investment in six centres: Azerbaijan, Russia and the Gulf of Mexico – where Holstein starting up this year, and Mad Dog, starting up in early 2005, would add 200,00 boe/d to BP, to be followed by Thunder Horse later in 2005 and Atlantis in 2006. Another of the key areas is Angola, which would see new production from BP's holdings in Kizomba A this year and Kizomba B in early 2005/2006, with the BP-operated Greater Plutonia coming onstream in 2007. Also key was Trinidad, which currently accounted for 75% of US LNG imports. He noted the way that successive offshore gas fields had been developed at progressively lower costs, and that Train 4 of the LNG facilities would start up in late 2005. The last of the six key areas for BP is Indonesia LNG, with the Tangguh project due to start up in 2007.

Inglis concluded that he remained very confident that BP was establishing a series of new profit centres able to deliver significant volumes of new oil and gas production.

Economic driving factors

Kieron McFadyen, Technical Director for Exploration and Production (EP) Europe, Shell, spoke of the 'Driving factors for oil and gas economics'. He started by saying that there could be no business as usual at a time of rapid change, change that came in various forms. There were the obvious challenges in existing business such as the North Sea where the UK would soon become dependent on non-indigenous supplies. In Europe generally, there were increasing environmental and pollution concerns, which meant there was a significant political component to ensuring commercial success. In a wider sense, political considerations – like the US ILSA (Iran-Libya Sanctions Act) – complicated company operations and access to potential investment areas.

He then observed the way that significant HSE improvements had been made in North Sea operations, with well operations now as safe as other aspects of the business. Similarly, oil spills had been halved and the volume involved reduced by two-thirds. In fact, a 95% reduction of oil spills to the North Sea had been achieved. However, it was important to recognise that more could always be done – the two fatalities on Brent Bravo reminded everyone of the costs of North Sea oil and the reason for always pressing forward with safety improvements. He commented that there were waves of improvement and it was important to keep pressing on to achieve higher levels.

McFadyen also pointed out that Shell had addressed the challenge of the North Sea by moving to a single E&P structure for the area. Increasing competitiveness involved leveraging assets and updating portfolios to remove those that could not achieve best-in-class benchmarks. Over the last two years Shell had reduced its UKCS acreage holdings by 50%, aided by the development of a market for North Sea asset trading.

Like the BP speaker, McFadyen highlighted the way that improving technology was aiding developments. He cited two examples – the way that the Skiff gas field had been developed at one-quarter of the normal cost, and the way that the Goldeneye gas/condensate development had been made financially attractive by eliminating offshore gas processing and doing it all onshore. Other technical innovations were opening up the deepwater regions and LNG, while innovations such as through-tube drilling (which Shell is currently doing on North Cormorant) could extend the life of mature assets. Similarly, innovations such as expandable tubing could significantly reduce well costs and open up new and mature areas. Changing supply patterns also had a role to play – following recent agreements, Statfjørd gas would now flow through the Brent system to St Fergus gas terminal. Also the Ormen Lange field, which is of such a size that it will increase Norwegian gas exports by 25% when the pipeline to East Anglia is completed and gas starts to flow in 2007.

He concluded his presentation on a positive note, explaining that Shell has reorganised for the future into three centres of excellence – Aberdeen for production, Stavanger for new projects, and Aachen for European gas. He pointed out that Shell continues to spend around $2bn/y in the North Sea, a vote of confidence justified because the company produces 25% of UKCS oil and one-third of UK gas. The North Sea has a 5bn barrel scope for recovery, which, with the recent framework treaty with Norway, ensures a productive future for the area.

Pricing renewables

Alan Raymant, Head of Renewables for Powergen, tackled the topic of pricing renewables and, much to the surprise of his audience, revealed that the intrinsic value of the power generated accounted for only 25% of its value to a generator. The other 75% being made up of the value of meeting the renewables obligation, the renewables obligation recycle value and the fiscal benefits of the exemption from the Climate Change Levy.

Dr Manoucher Takin, Senior Petroleum Upstream Analyst, Centre for Global Energy

In short, because government-derived obligations gave renewables three-quarters of their value, the primary risk was the political risk that government would change its mind. He saw the four key questions looking forward as:

- The level of political support?
- The obligation level?
- The eligibility?
- The supply/demand balance?

Raymant's view was that for investors in renewables, and assuming no radical change in the approval of the UK Government, a reasonable working assumption was for electricity prices in the £40–£70/MWh range for 2009/2010 when supply/demand would be tighter and fuel prices higher. However, for 2006/2007 around £30/MWh would be a safer guide.

Peter Goode, President of Schlumberger Information Solutions, talked of the role of pricing in supplier/contractor agreements. Predictably he felt the contracting oil companies had got a good deal from their suppliers which had helped them reduce their non-Opec finding costs from $23/b down to $6/b in little more than a decade. He argued that the most important advance had been in 3D seismic, which had revolutionised the industry by allowing it to clearly image a reservoir.

He said that the industry currently faced a series of challenges:

- Financial market pressure for returns.
- Difficulty of expanding production.
- Market volatility and price uncertainty.
- Tightening government regulations on health, safety and the environment.
- An ageing workforce

A key development in addressing some of these concerns is the remote control monitoring and operation of oil and gas fields. Each company had their own term for it – Smart field, Digital oil field, Field of the future, i-field, e-field and others – but Goode explained all referred to the linking together of a series of available technologies to give remote operation and monitoring. All the elements were in place for its widespread adoption, but the business case had to be made and the interests of the technologists and the business groups reconciled in order to take the application forward. In short, Goode's view was that to gain the benefits of the technology, the companies now needed to link them together and handle the problems of change management such a radical new approach would entail.

The morning session was completed by Boe Collins, President of Nymex, who looked at the way the trading of a range of energy derivatives had become an indispensible part of the oil and gas industry's day-to-day operations.

African and Middle East potential

The afternoon session started with Philippe Boisseau, Vice President Exploration & Production Middle East, Total, reviewing new production and development potential in Africa and the Middle East. He started by explaining that the bulk of incremental production was coming from offshore, particularly the deep waters over 500 metres. To date some 64bn boe had been discovered, with 75% in the three Atlantic provinces – West Africa, Gulf of Mexico and Brazil. Of these, West Africa has the largest share of the oil reserves – 44%, although only one-third of the overall total as it was not particularly gas prone. He noted that it would account for 30% of the 2002–2007 production growth for the top seven companies.

He gave a breakdown of the offshore reserves discovered so far as: Gulf of Mexico 12bn barrels oil, 2bn boe gas; offshore Brazil 11bn barrels oil, 1bn boe gas; West Africa 17bn barrels oil, 5bn

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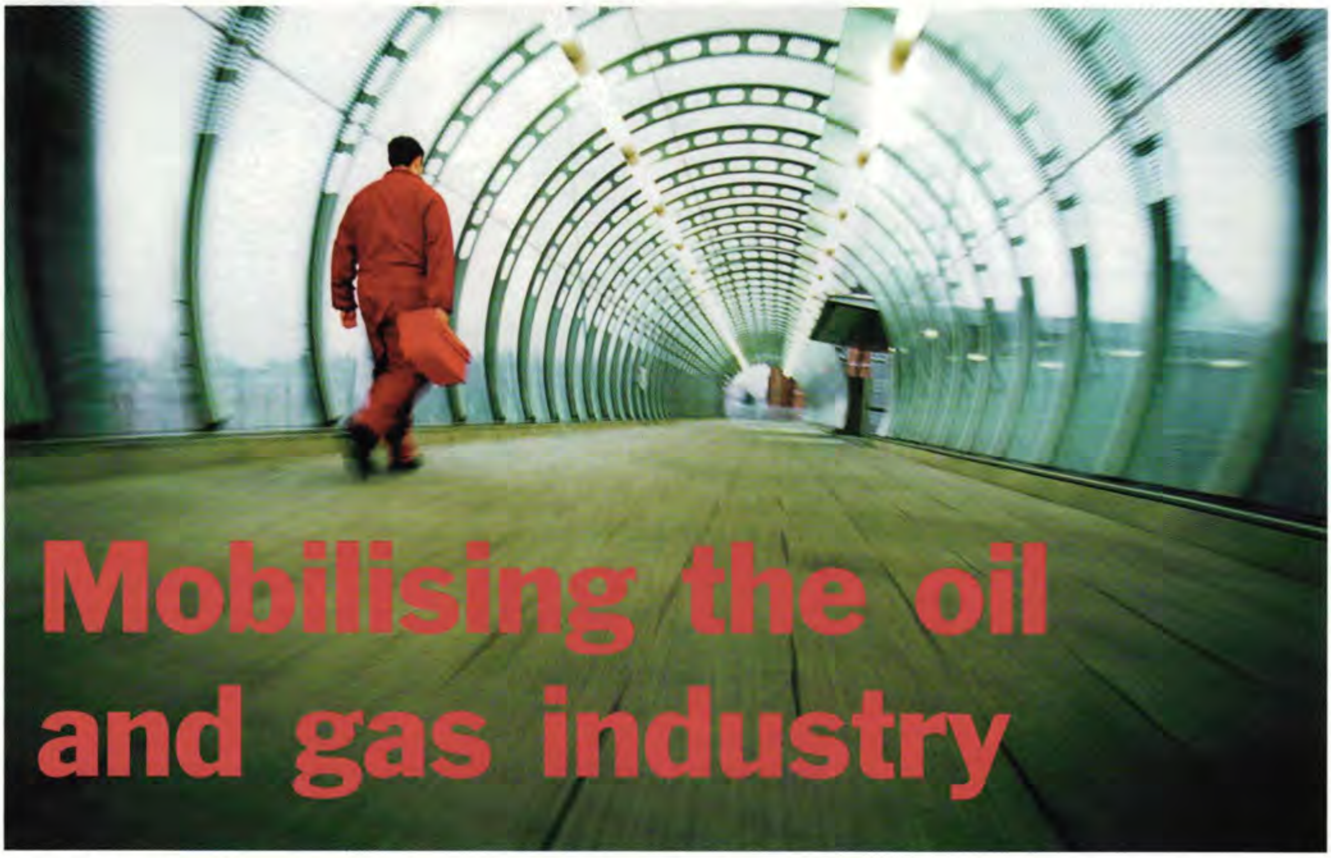

Mobilising the oil and gas industry

Mobility is about more than deploying the latest wireless equipment, it is also about changing the way people and organisations work. Here, *Tim Aikens*, Managing Consultant at BT Syntegra, looks at the opportunities, benefits and challenges that mobility brings to the oil and gas industry.

The mobile and wireless technologies available today offer the opportunity for anytime, anyplace computing capabilities. As the business world moves ever closer to operating in real time, the speed at which raw data can be translated into business intelligence has become a key differentiator. Rapid information exchange is particularly critical in industries such as oil and gas, where the value of time and data can rival that of physical assets.

Moving large volumes of data around the world securely, and in real or near real time, is becoming a significant competitive advantage, allowing key personnel to undertake swift analysis and make informed decisions regardless of location. The industry has always had a mobile workforce, be they drillers on a rig or maintenance staff in a refinery. They are often physically disconnected from organisational processes, yet still need access to information in as close to real time as is possible. This is where mobility can prove its worth – by adding value and increasing productivity.

Petrochemical companies have been implementing mobile technologies for some time. However, while some organisations are highly advanced in their use of wireless working, its application has often been piecemeal. There has not been a wholesale adoption of the concept of mobility. However, the industry's ongoing drive to reduce costs and increase refinery margins is placing pressure on organisations to consider mobile technologies.

This consideration presents a dilemma – the productivity benefits gained through faster information, rationalisation of people and processes, reduction in transportation costs and maximising the expertise of the workforce have to be offset against the costs and loss of capital available for core E&P development. The technology represents a significant investment, and it can result in major organisational and cultural changes. A clear business case, highlighting the main opportunities and benefits of adopting this technology, is needed.

Mobility technologies and their users

The first step is to identify who are the mobile workers, and to understand their precise needs. They can typically be categorised in one of three ways:

- *remote workers*, who work from home or in geographically distant locations remote from the source(s) of data;
- *itinerant workers*, who travel frequently between fixed locations;
- and, more specific to the petrochemicals sector, *on-site workers*, whose work is often across a large area or complex site, such as an offshore platform.

Although these categories present a different set of key requirements, benefits and opportunities, they are united in their need for real-time access to relevant data.

There are a number of technologies that apply to all. Most obvious are the devices such as PDAs, tablet PCs, smart phones and laptop computers – the visible face of mobility. However, mobility is about more than distributing wireless hardware.

Underpinning the adoption of the mobile technologies are the opportunities presented by increased bandwidth offered through fixed broadband, wireless GPRS and, finally, 3G. The sheer volume of traffic that can be transmitted over wider bandwidth has dramatic consequences. Voice and data can be sent simultaneously, enabling video conferencing and online meetings, while complex seismic data and 3D geological models can be transmitted from rig to shore or vice versa in real time, leading to significant cost savings on expensive time-priced assets.

The growth of web-based applications and web services has also facilitated the move towards greater mobility across organisations. These allow integration of existing software investments, reducing both the amount of software needed on any given device and the knowledge required by a user to operate it effectively. This is important in locations where ICT support is less easily available. For similar reasons self-help and self-healing technologies will also positively impact the move to full mobility. Web services and self-help allow ICT support to be concentrated in a smaller number of locations – it is interesting to observe how many oil companies now focus ICT and associated skills in a small number of sites.

Security developments, such as advanced encryption and firewalls, reduce the risks associated with the greater number of network access points engendered by disparate and mobile workers. In addition, automated back-up to corporate servers, rather than only on a mobile device, significantly reduces the risks and costs associated with lost or stolen equipment.

Field mobility

The considerable number of mobile knowledge workers in both upstream and downstream operations have, historically, used very paper-intensive methods to test, check, inspect, maintain and collect data on site. However, the advent of cheap, lightweight and intrinsically safe PDAs and tablet PCs is already changing the way essential work is carried out – in terms of people, processes and organisation.

There are numerous examples, but maintenance work provides an ideal illustration of the potential benefits. Planning and administrative management of maintenance requires job folders, maintenance records and necessary permits to be collated together prior to commencing work. New equipment and spare parts also need to be collected. This is a large paper and administrative

burden and can result in less than two-thirds of a 'traditional' shift being spent doing hands-on maintenance work.

Mobile technology enables workers to carry the necessary information to complete permit applications remotely – without resorting to paper. Personal productivity increases – less time is spent on preparation and more time is spent working. With a link to back-office inventory systems, equipment procurement also becomes more efficient. Repetitive data entry becomes unnecessary and scrawled notes made in the field no longer need to be interpreted, leading to improved data accuracy.

The latest developments in radio frequency identification (RFID) tags reduce human intervention even further (see *Petroleum Review*, February 2004). These tags offer a huge number of potential process improvements to the oil industry throughout upstream and downstream operations. Again using maintenance as an example, tags can be attached to assets and, through a PDA, used for automatic identification (auto-ID), displaying the full maintenance and service history. Because RFID does not rely on 'line of sight' this can be done whatever the prevalent conditions.

Understanding competency requirements and maintaining competency in the field is of critical importance to the oil and gas industry from both safety and operational viewpoints. Mobile technologies can provide instant access to a database of who has been trained to carry out specific tasks, and can instantly record when competency has been tested in the field, speeding up the process. It also increases the potential for selected multi-skilling, for example in a 'black-start' situation when more than the normal level of operational manpower is required.

As systems become more sophisticated and more reliable they are able to support correspondingly complex facilities. Perhaps the most extreme use of mobile technologies is for remotely operated platforms, of which the Norwegian Valhall field is the ideal example. So-called 'Smart' or 'E-fields' operated entirely from onshore result in a slimmer, more focused organisation (see *Petroleum Review*, December 2003 and January 2004).

Remote/travelling workers

Remote workers, with a more office-based background, also contribute to the leaner, more agile organisation. Security technologies such as IPSec (Internet protocol security) and MPLS (multi protocol label switching) have enabled secure Virtual Private Networks (VPNs) and Communities of Interest, which are already commonly used throughout the oil industry – in global 24/7 operational activity support services for example. Mobility means it is no longer necessary to have 100% of the organisation's required skills – such as E&P or ICT support – in each location.

Remote office and home workers reduce the amount of office space, plus associated facilities and the overheads required. Commuting times are reduced and flexible working patterns become possible. The overall result is a greater quality of life for employees, which, in turn, has a positive impact on employers, who experience individual productivity gains and lower staff turnover. Once the temporal and geographical restriction of the traditional nine-to-five desk-based job has been removed there is a greater diversity within the industry talent pool from which to recruit high-flying individuals.

Transport costs cannot be totally eliminated and some degree of travel remains inevitable within a global company. However, for these itinerant workers, mobility reduces the amount of 'down time' by enabling work whilst in transit and speeding up access to corporate data. Server and web-based applications permit an increased use of 'thin-client' laptops – and in some cases eliminate the need for a laptop altogether, as travellers access data from any available PC. The use of directory-based e-provisioning technology sets permissions and access levels as part of a single sign-on, maintaining the highest level of security regardless of where the employee is and with the minimum of effort.

Cultural and organisational changes

The net result of all this is that the workforce faces new pressures and different working patterns. The need for cultural and organisational change to allow for this is clearly evident. Managing a virtual team in disparate locations is a particular skill, which needs to be reflected in training and fast-tracking programmes. Similarly, remotely located workers need to be self-starting, with the ability to show initiative, take independent decisions and prove their reasoning after the event, rather than constantly checking with managers beforehand. These skills need to be included in recruitment and HR policy, and employees need to be empowered to work like this. The dynamics of a team alter – greater emphasis is placed on communication, time management and planning – and relationship-building needs to be formalised as informal practice falls away.

The impact of these kinds of changes needs to be weighed up with the more direct costs of a far-reaching technology implementation. There are significant benefits to be gained from the judicious deployment of mobility, but care needs to be taken, especially in brownfield locations where systems, people and culture are firmly entrenched.

How much is it going to cost? What is the business case? How will it affect legacy systems? Can it deliver promised productivity gains and return on investment? These are the very real questions that companies need to be asking. Mobility is not another flash-in-the-pan technology, as other sectors are already proving. However, it cannot be successfully implemented or deliver all the potential benefits if it continues to be adopted in a localised or half-hearted fashion. Because it impacts on every aspect of the organisation the decision to go mobile needs to be centrally led – and from the very top. Is there enough incentive for oil companies to overcome their inherent conservatism, embrace their innovative side and take on the challenges of a mobile future?

Photos courtesy of BT Iris

...continued from p35

boe gas; and other deepwater areas 2bn barrels oil, 14bn boe gas.

He observed Total's successful development of the Girassol field – with the world's largest FPSO, 40 subsea wells and riser towers – which was currently producing around 230,000 b/d. And then elaborated by saying that offshore Africa was likely to be the fastest growing area, with its share of offshore oil production rising from 8% in 2000 to 9% in 2010, 10% in 2020 and 11% in 2030. In the 2002–2008 period West African offshore oil production would increase rapidly to 3mn boe/d.

Turning to LNG prospects, Boisseau discussed the way a series of new LNG trades to Europe and the US were encouraging. Nigeria to US/Europe was already established, but Egypt to the US/Europe, Norway to the US/Europe and Angola to US/Europe were emerging new energy flows. He explained that moving Middle East LNG into West of Suez markets presented a challenge, but with Far East markets well supplied, even saturated, it was important to improve the economics of westward movements. His suggestions for achieving this included moving to much larger LNG carriers of over 200,000 cm and individual LNG trains of up to 7mn t/y.

He pointed out that gas usage in the Middle East was expanding rapidly and, by 2020, it was anticipated that 34bn cf/d would be used locally, with 12bn cf/d available for export as LNG. The largest current development for local gas use was the Dolphin project, which was a $4bn, 2.1bn cf/d development involving two offshore platforms and a 450-km pipeline from the Qatar North field to Abu Dhabi. He then noted that Total was involved in a similar sized project – South Pars 3/4, a $2bn investment involving 20 wells and two offshore platforms linked to shore by a 100-km multiphase pipeline. Production had built up from the 2002 start-up to full capacity of 2.3bn cf/d and 94,000 b/d of condensate.

Boisseau said that, in his view, gas-to-liquids (GTL) was not a very efficient process, with losses of 40–50% in the conversion. His view was that for the technology to become attractive the conversion loss needed to be 20% or less. His conclusion was that, until the technology improved for GTL, the only effective way to monetise remote gas was the LNG route.

Fuelling China

Paul Tempest, CEO of Windsor Energy then addressed the topic of fuelling China. He started by pointing out that China was economically larger than North America or Europe, but its rapid economic growth posed the question of how it was to be fuelled. Coal – China's traditional fuel – had fallen from 95% in 1960 to the current 70%, with the country accounting for 29% of world production and 28% of the world's consumption. It was notable, however, that despite strenuous efforts to reduce coal consumption for environmental reasons, 2002's production had exceeded 1996 levels.

Turning to oil, he observed that China had become a net importer in 1993 and had already become the world's second-largest oil consumer after the US. Already the fifth-largest oil importer, the country was expected to become the second-largest within 10 years.

Recent IEA projections suggested that China could be consuming between 20mn and 30mn b/d by 2030. Tempest's view was that it was difficult to envisage how the country could be fuelled at current price levels.

The remainder of the first day featured the Vice Minister of Energy and Mineral Resource of the Republic of Kazakhstan, Dr Manoucher Takin, talking on the prospects for Iraqi and Saudi oil production expansion, and John Williams, Manager, Exploration, ConocoPhillips, looking at future prospects. Reports on these and other events in IP Week 2004 will be covered in future issues of *Petroleum Review*.

KCA Deutag's T-57 rig

African focus for drilling company

KCA DEUTAG has recently experienced significant growth in its international offshore activities, winning contracts in West Africa, the Caspian and Russia. Securing the Benguela Belize contract offshore Angola further establishes the company's presence in Africa – where it already has land-drilling rigs active in Nigeria and Libya – and confirms the continent as a focus for further business development, reports *Maurice White*, CEO.

KCA DEUTAG secured its first major offshore contract in West Africa in 2003, with the award of a $120mn project by Cabinda Gulf Oil Company (CABGOC), a ChevronTexaco subsidiary operating offshore Angola. The contract involves the design, engineering, procurement, construction, commissioning and operation of a high specification, newbuild platform rig for CABGOC's Benguela Belize field development, part of ChevronTexaco's deepwater development in block 14. The installation of the rig will be followed by a five-year operation and maintenance period.

Block 14 is located some 50 miles offshore Angola, in approximately 1,400 ft of water, and will be developed by a drilling and production platform consisting of a compliant tower, and drilling and production topsides. It will have 42 well slots and, consequently, a significant primary drilling programme.

Schedule and progress

The project is being managed out of KCA DEUTAG's Houston office with a 15-man team co-located in National Oilwell's Ross Hill facility. In mid-November 2003 detailed engineering for the project was 80% complete. Earlier, in September, National Oilwell had awarded the fabrication sub-contract for the primary steel to Omega Natchiq in New Iberia, Louisiana.

Fabrication of the derrick equipment set and two support modules is now well under way, with a full-time KCA DEUTAG inspector and HSE supervisor located in the Omega Natchiq yard. The entire primary drilling equipment has been ordered and is currently under construction. The majority of the equipment is being manufactured in National Oilwell's Houston facilities – however, the drawworks is under manufacture in Edmonton and all the pipe handling equipment will be delivered from Stavanger.

The primary steel work is expected to be completed around March 2004. It will then be shipped via the Gulf coast intercoastal waterway to National Oilwell's Galena Park facility located on the Houston ship channel. Preparations are under way at Galena Park to receive the modules in March, with purpose-built skid rails currently being installed in the rig-up yard. The derrick equipment set (DES) will be placed on these rails and the two support modules located next to the DES in the same positions that they will be arranged offshore. The derrick, which at present is under fabrication at Galena Park, will then be added and the remaining drilling equipment, cabling, etc will be installed.

Following mechanical completion the rig will be ready for onshore commissioning and testing using temporary power at the end of 2004. The intention is to maximise the amount of onshore commissioning. A number

Schematic of Benguela Belize platform

The crew of KCA Deutag's T-43 rig achieved a world record for the first-ever application of an expandable sand screen/expendable casing packer (ESS/ECP) combination in a medium-radius side-track well. The Agbada-17st well was drilled offshore Nigeria for Shell Production Development Company (SPDC).

of the key drillcrew will be in the yard and will test all the rig systems, in particular the pipehandling systems. Following onshore commissioning the rig will be prepared for shipping by mid-February 2005. The transport and installation of the rig on the complaint tower is the responsibility of topsides contractor Daewoo Shipbuilding and Marine Engineering (DSME). Heerema has been subcontracted for this part of the work.

The 3,200-tonne rig will be installed in four lifts – the DES, two support modules and the derrick section above the 100-ft level. After the rig is lifted on, KCA DEUTAG will be responsible for offshore hook-up and commissioning. A total of 50 days has been allocated for this phase, part of a total 90-day topside commissioning programme. After acceptance of the rig, the first operations will be the tying back of six predrilled wells before commencing the five-year drilling programme.

Operations are slated to start around mid-2005.

North Africa

Whilst Benguela Belize is KCA DEUTAG's first offshore drilling contract in West Africa, the company has been active in North Africa for more than 40 years. During this time it has carried out land drilling operations in Algeria, Tunisia, Libya and Sudan. Currently it has onshore and offshore operations in Libya, where it works closely with the Libyan drilling contractor NWD (National Oil Wells Drilling and Workover Company).

Since 1958 the company has been working onshore Libya for Waha Oil, providing both staff and workover rigs. Three workover rigs – 101, 102 and 103 – are currently contracted to Waha Oil.

In addition, contract extensions valued at nearly \$8mn have just been announced in Libya for rig T-16, working for Agip Libya, and rig T-72, working for Wintershall Libya. Rig T-16, a 1,000 hp light drilling/heavy work over rig, is carrying out workover, repairs and side-track operations to 15,000 ft for Agip Oil, which it has been contracted to since 1981. Although owned by KCA DEUTAG, this part of the company operates in Libya as Haniel & Lueg – it has done so since 1961. It has worked for various companies, including Agip Oil, Wintershall, Veba (formerly Mobil), Sirte (formerly Esso) and Zueitina (formerly Occidental), with up to six rigs in operation at any one time.

KCA DEUTAG has also been working in Agip's Bouri field, offshore Libya, since 1998 – providing supervisory shore base and senior operations personnel to NWD to support its offshore drilling operations on the two Bouri platforms. KCA DEUTAG was responsible for re-activating the drilling facilities from their 'mothballed' condition. It has also overseen the engineering and installation of various platform projects, including an upgrading of the mud treatment system and installation of a common HP mud manifolding system.

Nigerian operations

Although Nigeria is a relatively recent area of operation for KCA DEUTAG – having begun operating out of Port Harcourt, Rivers State, in 1987 – the company is just as well established there as it is in Libya. It has operated as many as five land rigs for clients such as Shell Petroleum Development Company (SPDC), Pan Ocean and Nigerian Agip Oil Company (NAOC), and has undertaken conceptual engineering work on a number of developments offshore Nigeria.

During 2002, Pan Ocean Oil Corporation awarded a two-year contract with extensions to KCA DEUTAG for rig T-57. Also that year, the Nigerian Agip Oil Company awarded KCA a two-year contract with a one-year optional extension for rig T-6, a 1,000 hp rig.

The most recent contract came at the end of 2003, when KCA DEUTAG was awarded a two-year contract with one-year extension from NAOC Agip for rig T-26.

KCA DEUTAG's Nigerian facilities include a heavy transport fleet for rig moves and logistic support of the rigs, an independent workshop to maintain the fleet and engineering support of the rigs, and a computerised warehouse with a comprehensive stock of spares to efficiently support remote area operations. In addition, the company has established a number of safety and drilling records in Nigeria, some of them world records, and it continues to win new business.

Marginal field initiative raises political tensions

Recently awarded marginal fields in the Niger Delta are benefiting from a number of fiscal incentives. These offer excellent technical and commercial opportunities for indigenous Nigerian companies to develop reserves that have remained commercially unattractive for many years. If successful, the programme will loosen the grip of the oil majors on some key parts of the upstream oil sector and could herald rapid expansion of an independent sector. However, the greatest challenge in developing these fields is the complex relationships between all the stakeholders involved and ongoing conflicts with the Delta communities, reports *David Wood*.*

Nigerian E&P joint ventures (JVs), involving 60% participation by Nigerian National Petroleum Corporation (NNPC) – except in the case of Shell where it is 55% – account for more than 95% of Nigeria's oil production (see **Table 1**).[1] This situation is set to change rapidly as some of the large deepwater oil fields, developed by the majors under production sharing contracts (PSCs)[2], start to contribute significant volumes of production. For example, when the Bonga field offshore Nigeria comes onstream during 2004, Shell will operate some 50% of the country's oil production. That said, the majors will remain very much in the operational driving seat.

A marginal field initiative has been progressing in Nigeria for several years, its main objectives:

- to reduce the stranglehold the joint ventures, particularly the foreign major oil companies, have on the onshore and shallow water Nigerian oil sector;
- to encourage wider participation from an indigenous oil and gas sector; and
- to develop fallow acreage.

An indigenous industry has also emerged over the past 15 years, with companies such as Dubri Oil producing small quantities of oil – although much less than the 150,000 b/d quota allocated to them by the Nigerian Government.

The Department of Petroleum Resources (DPR) – the government ministry responsible for licensing and fiscal terms – has identified some 116 fallow marginal fields (with potential production <10,000 b/d and undeveloped for more than 10 years), holding a combined reserves potential estimated by DPR at up to 1.3bn barrels.

Some 24 of these fields were selected in 2001 by the DPR, following discussions with the JV partners, as suitable for offering to indigenous operators. These fields are estimated by the existing JV operators to hold reserves of some 214mn barrels – but in many cases these reserves assessments are very speculative, being based upon a poor database of one or two old wells only. The expected average size of these fields is less than 10mn barrels, but upside potential to in excess of 50mn barrels cannot be ruled out in some cases.

Long, slow licensing process

The Petroleum (Amendment) Decree No. 23 of 1996 was enacted to promote the participation of indigenous Nigerian companies in the development of small oil fields that remained uneconomic to the JVs. This was followed in March 2001 by the initial announcement that there would be a marginal field licensing round. Guidelines were issued by the DPR in July 2001, outlining a farmout process. The indigenous companies had to pre-qualify by submitting detailed applications by September 2001. The results of the pre-qualification process were announced, several months later than expected, in June 2002 – listing up to five companies per field (from the 142 originally expressing interest) that would be allowed to enter bids on the fields being offered. The bidding process required separate detailed technical and commercial bids to be submitted by September 2002 (71 bids were submitted) and the winning bidders (or 'preferred farmee') were announced in February 2003.

The bidding round guidelines stated that the 'preferred farmee' and the JV holding the oil mining licence should then negotiate a farmout agreement for each oil field within 90 days. The final awards and payments of a $150,000 signature bonus to the DPR were expected in June 2003 – however, the negotiations of the farmout agreements was protracted and difficult, lasting until December 2003, with most agreements signed and signature bonuses paid in January 2004. The difficulties revolved around several concerns raised by the major foreign companies regarding their ongoing exposure to liabilities associated with the marginal fields (see below).

Complex stakeholder interfaces

The difficulty in agreeing terms for the farmout agreements highlights the complex and conflicting interests of all the parties potentially involved in marginal licensing. As shown in **Figure 1**, the big oil companies of the JVs are caught very much in a wedge between

the Nigerian Government and the volatile Delta communities. Future marginal field operators need to tread carefully to avoid being sucked into the same position as the larger foreign operators.

The position of NNPC is more complex than actually indicated in **Figure 1**, because it has a foot in both the Federal Government camp (as the state oil company) and, as the major shareholder (but not operator) in the JVs, its fortunes are inexorably tied to the performance of the major foreign operators. Conflicts with the oil majors and shutdowns in the Delta areas also severely impact on NNPC's performance. It works the other way too, many in the Delta communities perceive the foreign majors as *de facto* representatives of Federal Government in their regions, with more power and money than the local government institutions, and therefore expect them to deliver all kinds of social and welfare benefits over and above what is usually expected from business organisations.

The various Delta communities feel dispossessed because the Federal Government took control of all mineral rights and surface land ownership several decades ago. Communities in the Delta have made way for oil developments, with all the major revenues going directly into federal coffers and relatively little historically filtering down to Delta state (regional and local government) level.

Both within the Delta communities and, more tellingly, within the indigenous oil industry, the foreign major companies are commonly perceived as the cause and blamed – sometimes unfairly – for all the problems that arise. Limited employment opportunities with the major companies, most of which are now strategically refocusing resources to their deepwater licences, provide little compensation for the environmental and social impact that more than four decades of oil development has had on the Delta landscape.

Licence Type	Major Licence Holders	Estimated capacity (000) b/day		Percent of Total Capacity	
JV	Shell (operator), 30%, NNPC, 55%, Total, 10%, Agip, 5%	1280		47.4%	
JV	ExxonMobil (operator), 40%, NNPC, 60%	550		20.4%	
JV	ChevronTexaco* (operator), 40%, NNPC, 60%	450		16.7%	
JV	Agip (operator), 20%, ConocoPhillips, 20%, NNPC, 60%	130		4.8%	
JV	Total (operator), 40%, NNPC, 60%	120		4.4%	
JV	ChevronTexaco** (operator), 40%, NNPC, 60%	70		2.6%	
JV	Total (Major JV Licences)		2600		96.3%
JV	Pan Ocean (operator), 40%, NNPC, 60%	20		0.7%	
PSC	Addax (operator), NNPC, 100%	20		0.7%	
PSC	Agip (operator), NNPC, 100%	10		0.4%	
	NNPC (operator), 100%	30		1.1%	
	Others	20		0.7%	
	Total (Oil & Condensate)	2700		100%	

Notes:	Total condensate Production is about 300,000 b/d
	The merger of former Chevrons Nigerian subsidiary with formerTexaco Nigerian subsidiary has not yet been implemented.
	Major production from deepwater PSC's due onstream from late 2003

David Wood & Associates

Table 1: Nigeria's producing ventures, as at June 2003

Field Name	Orignial Joint Venture Operator	Indigenous Companies Receiving Awards	Licence OML	Number of Wells
Asuokpu/Umutu	SPDC	Platform Petroleum	38	6
Asaramatoru	SPDC	Prime Energy(51%):Suffolk (49%)	11	2
Atala	SPDC	Bayelsa Oil Co Ltd	46	1
Eremor	SPDC	Excel Energy & Pet	46	4
Ibigwe	SPDC	WalterSmith (70%): Morris Pet. (30%)	16	3
Ofa	SPDC	Independent Energy	30	1
Oza	SPDC	Millenium Oil & Gas	11	4
Qua Ibo	SPDC	Network Energy & Pet.	13	2
Stubb Creek	SPDC	Universal Energy	14	4
Tom Shot Bank	SPDC	Associated Oil & Gas: Geo Energy	14	2
Tsekelewu	SPDC	Sahara Energy (51%): African O&G (49%)	40	1
Uquo	SPDC	Frontier Oil	13	4
Ororo	Ctex	Guarantee Pet Ltd.: Owena Oil & Gas	95	1
Akepo	Ctex	Sogenal	90	1 + ST
Ogedeh	Ctex	Bicta	90	2
Ajapa	Ctex	Brittanie-U Nigeria	90	1
Dawes Island	Ctex	Eurafric Limited	54	1
KE	Ctex	Del Sigma	54	1
Oriri	Ctex	Goland Petroleum	88	1
Ekeh	Ctex	Movido Energy & Pet.	88	1
Umusadege	EPNL	Mid-Western O&G (70%):Suntrust (30%)	56	3
Obodogwa/Obodeti	EPNL	Energia Co Ltd: Unipetrol Development	56	4
Umusati/Igbuku	EPNL	Pillar Oil Limited	56	3
Amoji/Matsogo/Igbolo	EPNL	Chorus Energy	56	6

SPDC = Shell/Total/ENI/NNPC JV: EPNL = Total /NNPC JV: Ctex = ChevronTexaco / NNPC JV

Table 2: Nigerian marginal fields awarded in December 2003

Context of conflict

It is important to put into context the long-standing and entrenched negative regard in which the Delta communities regard the JV (oil majors and NNPC). A report[3] compiled by CDA (Collaborative For Development Action), based on field studies in the Delta and analysis from both oil industry and community perspectives in 2001 and 2002, provides a detailed account of the complex relationships. It states: 'Oil companies operate in parts of Nigeria where 70% of communities lack access to clean water, electricity, passable roads and bridges to connect riverine communities. Successive military and civilian administrations have largely left communities in these oil-bearing states underdeveloped, while resources from these areas have been used to develop other parts of the country. Oil companies therefore bear the brunt of the deep hostilities resulting from decades of neglect by the central government.'

The dynamics surrounding interactions between companies and communities typically occurs on an *ad hoc* basis, usually triggered by a protest or the need to negotiate contracts. It is focused on fragmented communities rather than larger clans and often sidelines local government. Dialogue takes place with local elders, youth groups or others that hold power, often violently, at the village level, usually at company offices as company managers are often afraid to make on-site visits to the communities. This dialogue usually lacks transparency to the wider Delta community. Conflicts exist in the Delta in a tripartite manner – between communities; between the Delta population and the Federal Government and/or JV operators; and between the government and the JV operators (catching NNPC in the middle).

The contracting process to provide services to the oil companies by the Delta communities underlies many problems and has reinforced negative actions such as extortion, corruption, vandalism, sabotage, theft, fraud, general violence, undermining traditional authority and intimidation that enables a few to often illegitimately gain access

Terrain	Oil Production Rates Barrels/Day Prod <2000bopd	2000<Prod <5000 bopd	5000<Prod< 10000 bopd	10000<Prod <15000 bopd	Prod>15000 bopd
Onshore Land/Swamp	6.50%	15.00%	20.00%	20.00%	20.00%
Offshore WD<100m	2.50%	7.50%	12.50%	18.50%	18.50%
Offshore 100m<WD<200m	1.50%	3.00%	5.00%	10.00%	16.67%

David Wood & Associates (after DPR 2002)

Table 3: Royalty rates for Nigeria's marginal fields

to the cash available from the oil companies. This, in turn, has exacerbated the negative perceptions the Delta population as a whole has of the foreign oil majors.

The oil companies have to shoulder part of the responsibility for this by establishing unsatisfactory and corruptible contracting procedures and controls. Monitoring of the contracts from oil companies to community projects is poorly audited by the multi-national audit companies (not wishing to endanger their own staff) and is often hindered by the fact that senior company officials are members of ethnic groups (often Yoruba or Igbo) from outside the Niger Delta. These 'outsiders' are perceived as having greater access to educational and economic opportunities than their counterparts from within the Niger Delta.

It will be a long haul for the oil majors to change perceptions and relationships with the Delta population as a whole. The way forward will have to include focus on some of the non-financial aspects of relationships with communities; rewarding peace rather than conflict and communities rather than individuals; and engaging in broader, on-site, pro-active, on-going dialogue.[3] Shell seems to be making some progress in this regard,[4] but many local successes are required to change wider public perceptions of the major foreign oil companies as the main villains.

Contractual implications for marginal fields

Financial institutions, local and international independent oil companies wishing to fund and/or joint venture with the indigenous companies that ultimately negotiate rights to the marginal fields, as well as service companies and suppliers to those operations, also have to address the issues surrounding community relations within the Delta. They need to be comfortable that the fiscal and contract terms with government and the JVs are appropriate, and share responsibilities and liabilities equitably.

Figure 2 illustrates the complex contractual network that must be established for the funding and operation of marginal fields under a farmout process. Dovetailing credit agreements from financial institutions and assignments of working interests to foreign companies will be both a legal and operational challenge.

To retain their preferential fiscal status indigenous companies are not allowed to assign more than 40% interest to a foreign backer. Reports from within the industry, however, suggest that several of the new marginal field operators, strapped for cash, are entering unofficial side agreements with foreign independents for them to provide all the necessary capital investments in return for an 80%:20% split of future revenues. Such independents should study carefully the evolution of interest holdings and ChevronTexaco's experience in the Agbami field to see the political risks associated with such deals and how they are liable to unravel if and when returns on investments materialise.[5]

Farmouts must address diverse issues

It is not just the commercial terms – such as what percentage of over-riding royalty (the option preferred in the current round of agreements) or net profit interest or $/b tariff that can be agreed as payment to the JV OML holders – that are crucial clauses in these agreements. Other terms are also crucial and have proved difficult to agree. These include:

- Indemnity and insurance
- Ring fence around farmout area
- Appraisal and deep drilling rights
- Abandonment and site restoration
- Unitisation of fields that straddle OMLs
- Payment terms
- Default as well as non-performance penalties
- Access to infrastructure
- Common usage of facilities
- Sole risk basis of operation
- Extent of government's right of back-in
- Termination for lack of activity
- Community relationship
- Safe operations
- Oil spills and associated environmental damage

Some additional concerns of the majors have centred on extracting performance guarantee bonds and some reassurances from the Federal Government regarding operations of the local firms in the fields. These include:

- How will any oil produced by new indigenous operators be produced within Nigeria's tight Opec quota? (Quota set from November 2003 at 2.018mn b/d, with national capacity approaching 3mn b/d). The majors do not want to be obliged to shut-in their oil to enable indigenous producers to produce. This will become an even more pressing issue as more of the majors' deepwater production comes onstream, unless the dynamics of the Opec quota system change, granting Nigeria a larger share of production.
- Liabilities, including exposure to bad operators, and guarantees that indigenous firms can, and will, meet their financial liabilities.
- Guarantee of the competence of the indigenous operator.
- Gas flare-out programmes of the indigenous operators will not impact those of the JVs, which are working towards eliminating gas flaring by 2008. The extra cost of installing gas handling facilities could make several of the marginal fields sub-commercial. Indigenous operators can therefore be expected to seek ways to bend the rules.

The JV operators felt caught between a rock and a hard place in these negotiations. They took a firm line during the negotiations and were accused of exploiting local industry and communities. They have finally accepted quite tightly drafted agreements – with indemnities and guaran-

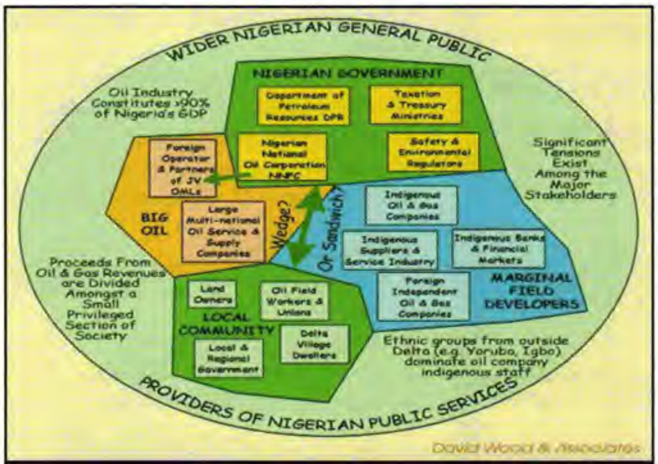

Figure 1: Stakeholder interfaces for Nigerian marginal fields Nigeria (2001 to 2003)

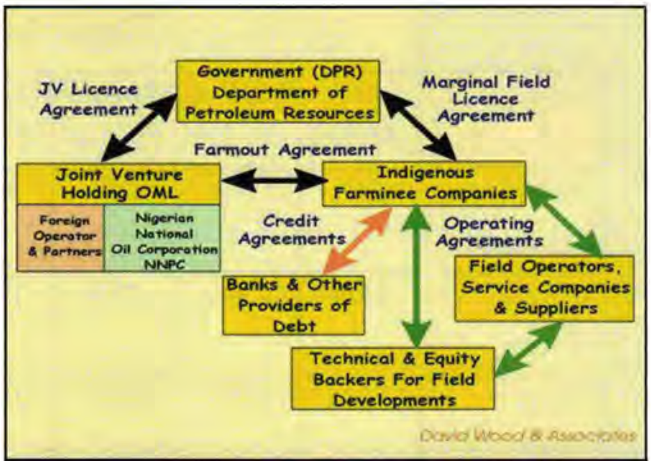

Figure 2: Negotiation interfaces for marginal fields tendered in Nigeria, 2001–2003

tees associated with the issues outlined above – from the indigenous operators and Federal Government. However, the majors remain at risk, from a public relations standpoint at least, if those operators subsequently cause environmental damage, accidents or fail to meet their community development pledges, perhaps followed by bankruptcy. In such situations the local communities will still blame and turn to the JV operators for solutions to any problems caused.

Table 2 lists the 24 marginal fields awarded, the former licence holders, the new licencees and the estimated field reserves. Some 17 fields were awarded to sole operators and seven fields to joint venture partnerships as reported in the Nigerian press.[6] Many of the new operators have little upstream oil and gas operating experience, some are oil trading companies, others shippers, suppliers or service companies to the industry. Almost all require additional financial and technical partners in order to commence their work programmes.

Significantly, four Delta states – Rivers, Akwa Ibom, Ondo, and Bayelsa – have floated private companies and have been awarded fields (for example, Akwa Ibom owns a share of Universal Energy and has been awarded the Stubb Creek field). This direct involvement of the Delta states will raise expectations within their communities and may add an extra complication to attracting foreign investors into such field developments.

Improved fiscal terms

These marginal fields contain reserves volumes that are immaterial to the major oil companies, but are not commercial for them to develop because of the high levels of taxes and NNPC participation of between 55% to 60%. Companies operating under the JV structure currently pay 20% royalty onshore, 18.5% in water depths up to 100 metres and 16.667% in deeper water. They also pay 85% petroleum profits tax (PPT) on exported crude and 65.75% on oil and gas sold domestically within Nigeria and until development costs are recovered.

Even though the joint venture partners (including NNPC) have been entitled since 1986 to a 'guaranteed' minimum profit safeguard – in the form of reduced government take or rebate on PPT – based on a Memorandum of Understanding, such incentives do not enable small fields to be developed commercially under the current JV fiscal structure. Operators obtain a 'minimum guaranteed notional margin' of $2.5/b specified in the MoU if they keep their 'technical cost' (capital and operating costs) below $4/b – an almost impossible task for marginal fields. This safeguard increases to $2.7/b for capital investment above $2/b. This uniquely Nigerian system has added flexibility and downside protection for the JV partners in production from their already developed fields during times of low oil price.[1]

To help marginal fields to become commercially viable for the indigenous operators the DPR has introduced more flexible and lenient fiscal terms, including sliding scale royalties (see **Table 3**), PPT reduced to 16.75% for the first five years of production, and an improved investment tax allowance of 10% (15% in water depths to 100 metres; 20% in deeper water) on qualifying capital expenditure.[7] These terms make a substantial difference to the commercial viability of small fields. In the absence of the complicating factors of community issues and contractual obligations to the JV partners, such terms should enable several indigenous operators to achieve profitable field developments from the set of marginal fields recently awarded.

Full credit should be given to the DPR for recognising the need for flexible fiscal terms to optimise the development of Nigeria's oil and gas resources. These range from the PSC arrangements for large deepwater fields, through the standard tax and royalty terms applied to the JV, modified by the MoU under specific conditions, down to those incentives described above for marginal fields, plus various tax incentives associated with commercial upstream and downstream gas developments.

Currently, gas sold into the domestic Nigerian market attracts prices of only $0.8/mn Btu or less. This is expected to change with the many gas utilisation projects being developed, but the no flaring restrictions will put pressure on majors to dispose of gas at very low prices in order to maintain oil production rates. Interestingly, some of the marginal fields are predominantly gas (eg the Matsogo field awarded to Chorus Energy) indicating that some indigenous companies see future value in the domestic market for gas.

To sum up

Recently awarded marginal fields benefit from fiscal incentives and offer excellent technical and commercial opportunities for indigenous Nigerian companies to develop reserves that have remained commercially unattractive for many years. If successful, this programme will loosen the grip of the oil majors on some key parts of the upstream oil sector and could herald rapid expansion of an independent sector.

However, it is not the fiscal or technical issues that are likely to pose the greatest challenges in developing these fields, rather the complex relationships between all the stakeholders involved and ongoing conflicts with the Delta communities. The independent sector will also have to come to terms with the compensation and dependency culture that is now endemic in parts of the Delta. The clock is now ticking for development activity to commence, as the new operators have to complete agreed work programmes within 24 months of the awards. Unfortunately, many of the new operators have yet to raise sufficient funds or to establish appropriate technical expertise.

Major oil companies operating in the Niger Delta feel that they are at the whim of violence and conflict related to social and political forces. Although they are beginning to restructure the impact of their operational policies on local dynamics, the current marginal field initiative poses both threats and opportunities in this regard. A collaborative approach between the majors and the independent (indigenous and foreign) sectors seems to offer the best way forward and may ultimately allow all parties to benefit from the development of marginal assets. If successful, it could pave the way for passing other maturing assets, immaterial to the majors, into the hands of an enterprising and innovative independent sector.

However, the foreign independent oil and gas operators – to date poorly represented within Nigeria – that are planning to farm-in to the marginal fields, will have to learn rapidly from the mistakes made by the majors in handling community relationships, and carefully factor in geopolitics and above-ground risks into their economic assessments.

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Notes and references

1. For more details on recent industry activity in Nigeria see *Petroleum Economist*, June 2003.
2. David Wood, 'Evolution and economic performance of production sharing terms' (Nigeria), *Petroleum Review*, January 2003.
3. Luc Zandvliet with Ibiba Don Pedro, 'Oil company policies in the Niger Delta', CDA (Collaborative For Development Action), June 2002, available at **www.cdainc.com/cep/cepcasestudylist.htm**
4. Business Partners for Development, 'Partnering and Environmental Impact Assessment: Case Study of Shell's Utapate Oil Field Re-Development', 2002, available at **www.bpd-naturalresources.org**
5. Famfa, an indigenous company, signed OPL 216 on favourable JV terms in the mid-1990s and farmed out 40% to Texaco. Following seismic and the identification of a big structure Texaco paid Famfa several million dollars for an additional 20% net revenue interest in the licence. When the giant Agbami field was discovered in 1999, Famfa wanted to renegotiate its deal and NNPC wanted to back-into the licence for 40%, according to its rights. A legal stand-off ensued, which has delayed field development by more than four years and the State in late 2003 imposed a working interest settlement reported to be 10% Famfa, 50% NNPC and 40% (foreign JV partners – 32% ChevronTexaco and 8% Petrobras). That unofficial deal turned out badly for both the indigenous company and the foreign major.
6. **www.nigeriafirst.org** 23 December 2003.
7. More information available from DPR website at **www.dprnigeria.com**

Letters to the Editor

Reserves revisions

Dear Sir,
In your February Editorial you call for an independent audit of reserves. As a consultant reservoir engineer I would not disagree, but as an investor, I feel it might add another layer of unproductive bureaucracy. Surely there is an easier way to restore trust in the industry? Simply requiring each company to report their reserves on a field-by-field basis would remove the possibility for any sleight of hand. Currently, many companies report reserves on a regional basis and, in addition, there is no need for reserves to be reported when they are established. As a consequence, reserve bookings can be 'managed' and the inevitable corrections disguised. Transparency of reserves would present a true picture of the state of the industry and allow for realistic calculations of essential metrics such as finding cost and replacement ratio.

Certainly, there may be some initial embarassment as Company A realises that its bookings for a field do not match the operator's but, if they can justify the differences, why not? If they cannot justify the difference then they should not be booking a different figure. One would expect the differences to balance out and the embarrassment to be small. How much more embarrassing is it for the industry when a respected company like Shell has to revise its reserves by 20%.

This openness could cause confusion in companies which book proven reserves at a 90% confidence level – arithmetic addition of those values will give a proven total which has a much higher level of certainty and would yield a lower figure than probabilistic addition. However, many companies already opt for arithmetic addition even if it does not understate reserves, and it would be trivial for those using a more appropriate probabilistic sum to report both values. Apart from these initial, easily avoided problems, are there any other reasons for the current secrecy?

David Morgan
Uncertainty Management, Hertford Heath

I have just received a reserves update from Woodside, which breaks down its reserves into proved, probable and scope-for-recovery. It is also broken down by individual fields, or two fields where these are being jointly developed. In addition, a named individual has compiled the information and 'consented in writing to its inclusion'.

Woodside appears to have supplied all the information that might reasonably be included and without the unproductive bureaucracy that David Morgan is rightly concerned about.

The only question left is 'Will other companies follow Woodside's lead?'

Chris Skrebowski
Editor, Petroleum Review

Non-opec output

Dear Sir,
We have just read your February issue, which contains several excellent articles. However, as may already have been brought to your attention, we believe that you have incorrectly interpreted in your Editorial – the non-Opec oil production numbers which you have taken from the *BP Statistical Review*.

The bottom line in the table on p2 described as 'Total non-Opec' and amounting to 36,214,000 b/d excludes FSU oil production, as footnoted by BP. The FSU production numbers should be added, not subtracted, to arrive at 'Total non-Opec'. You have, in effect, deducted FSU from a number, which already excludes it. Consequently, it can be seen that non-Opec oil production outside the FSU has been rising each year in the BP series since 1992, except in 1999. It did not peak in 1998 as you have stated in your Editorial, but has continued to increase, even up to 2004 according to the IEA and our assessment.

It is unfortunate that your well-respected and influential publication should print such a misleading analysis and conclusion on this very important topic.

It should also be noted that non-Opec oil production is frequently increased by improving recovery rates from existing reserves and by linking small 'stranded' oil fields, which are not economic to develop on their own, to adjacent pipeline systems. The lack of new large oil discoveries in a particular year does not, therefore, necessarily mean an end to the growth of non-Opec oil production.

Roy Jordan
Energy Market Consultants (EMC), London

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