Petroleum review

NOVEMBER 2004

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

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover picture: A booming oil and gas sector has to be sensitive to ancient traditions. Chao Phraya River, Bangkok, Thailand. Photo: Ian Laing

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ROUNDUP

From the Editor

Planning for a soft landing

With oil prices nudging $55/b the general media is once again full of instant commentary about the seriousness or non-seriousness of the situation. It therefore seems appropriate to try to separate facts from conjecture.

A near synchronous economic recovery around the world has produced strong demand for oil products and, in consequence, high spot prices for crude. The steady and progressive rise in the spot price tends to confirm the view that this is basically demand driven, with speculative activity simply adding swings around an upward trend.

The large and expanding price differential between high and low sulphur crudes tends to confirm the view that desulphurisation plant capacity is now the bottleneck in most refineries. This means that to maximise throughput and meet demand that is heavily light-product skewed, refiners find it economic to bid up the price of light low sulphur crudes rather than accept the effective capacity loss of running cheaper, heavier and higher sulphur crudes.

At the moment crude production capacity is clearly under strain. The stimulus of high prices means that all non-Opec production is being operated flat out. New production capacity is being brought onstream as fast as possible. However, a combination of recent start-ups and project slippage means there is very little incremental production coming onstream before the new year.

According to the International Energy Agency's (IEA) latest (October) *Oil Market Report*, in September Iraqi production reached 2.33mn b/d – one of the highest levels seen since the invasion of the country in April 2003. The report shows the other Opec producers were operating virtually flat out. Collectively, Opec including Iraq produced 29.91mn b/d of crude and a further 4.38mn b/d of condensates, to give an all-time record Opec production of 34.29mn b/d in September.

According to the IEA, Opec's spare capacity (reached within 30 days and sustainable for 90 days) is now just 580,000 b/d, of which 180,000 b/d is in Iraq. What this tells us is that the world's spare capacity is now just 0.5%.

It therefore follows that with little or no additional supplies on the immediate horizon prices will rise to balance supply and demand. How high spot prices will go depends on how quickly demand slows, how severe the Northern Hemisphere winter is and how panicky the market gets.

This, in turn, raises the question of how strategic stocks should be used. The usual view is that stocks should only be released at the point of some predetermined shortfall in supplies – usually 7%. Following recent hurricane losses some US Gulf Coast refiners received loans of crude from the US strategic stockpile.

While Opec had significant spare capacity, seasonal demand swings were accommodated by varying Opec production. More recently, reduced industry stocks and Opec determination to keep stock levels low means seasonal demand variations are now creating costly and damaging price swings. Perhaps it is time to rethink how strategic stocks are used? Could formal loans of crude from strategic stocks be a way of smoothing flows and avoiding price spikes? Earnings from the loans could potentially finance expansion of the strategic stocks to the benefit of all.

For the moment the hope and expectation is that as we move into 2005 new capacity and slowing demand will bring the market into a more comfortable balance at rather lower prices. High prices provide the incentive for companies to expand production and for the consumers to use it more efficiently. But, for this benign adaptation to occur significant time is needed. If things happen too fast the danger is that oil prices spike, demand is poleaxed and prices then collapse.

In this respect, the latest (October) IEA report is not encouraging. It has revised global demand for 2004, up by 240,000 b/d to 82.4mn b/d, and trimmed growth in 2005 by 70,000 b/d to 83.9mn b/d. It is easy to criticise the oil companies for not investing in enough new capacity, but the variations in demand growth have been little short of amazing: 2001 – 0.3mn b/d, 2002 – 0.4mn b/d, 2003 – started at 1.1mn b/d and ended at 1.8mn b/d, 2004 – started at 1.2mn b/d, now expected to be 2.7mn b/d, 2005 – expected to be 1.5mn b/d.

Chris Skrebowski

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

eworld

Shell recently posted its *1999–2003 Financial and Operational Information* booklet, otherwise known as the 'Five Year Book', on its website – **www.shell.com/faoi** As in previous years, the booklet contains detailed information about Shell's financial and operational performance over the past five years, including maps showing the locations of its major assets. A new quarterly e-newsletter has also been launched by Shell US in a bid to keep US readers up to date with news and stories from all over the group.

New moves to encourage further investment in renewable energy were recently outlined by the UK government. The proposals – published in the consultation document Renewables Obligation Order 2005 – will strengthen the development of electricity generation capacity using renewable energy sources in the UK. A wider review of the Renewables Obligation will be taking place in 2005/2006. The UK government's proposals on the terms of reference for this Review can be found at **www.dti.gov.uk/energy/renewables/policy/terms_of_reference.shtml** Information about the Renewables Obligation Order 2002, the key mechanism to help achieve the UK's renewable energy targets, can be found at **www.dti.gov.uk/energy/renewables/policy/renewables_obligation.shtml**

The newly-appointed UK Energy Minister, Mike O'Brien, has allocated £16.5mnn of government funding to nine UK coal mines under the second application period of the Coal Investment Aid (CIA) initiative. See the DTI website at **www.dti.gov.uk/energy/coal/invest_aid/index.shtml**

UK-based Online Data has introduced a number of new links to its oil and gas website at **www.oilvoice.com** including at new reports and commentary section providing an archive of oil company/industry articles covering the complete spectrum of energy-related issues. The site also provides global company overviews, a bulletin board where service companies and oil industry organisations can post news and information.

Sibneft has published online its Russian-language corporate magazine *Sibirskaya Neft (Siberian Oil)* at **www.journal.sibneft.ru** The magazine is published bi-monthly.

In Brief

UK

Shell (49%), ExxonMobil (39%), Paladin *Resources (7.5%) and Centrica Energy (4.5%) have brought onstream the Goldeneye field in the South Halibut Basin area of the Outer Moray Firth. The field straddles blocks 20/4b, 20/3b and 14/28b. Goldeneye will provide around 3% of the UK's gas demand. Production is expected to plateau at 300mn cf/d of gas and associated liquids.*

Overall BP production in 3Q2004 is *expected to be around 3,880mn boe/d, up by some 11% from 3,502mn boe/d in 3Q2003, but 2% lower than the rate of 3,971mn boe/d in 2Q2004. Average production for 2004 as a whole is expected to be over 4mn boe/d, an increase of more than 10% compared to 2003.*

Venture Production (50%) and Dana *Petroleum (50%) have secured government approval for the development of the Gadwall oil field in block 21/19, within the Greater Kittiwake Area (GLA) of the central North Sea. Gadwall will be developed as a subsea tie-back to the Kittiwake platform utilising a single producer/injector pair of wells. Estimated proven and probable recoverable reserves for the field are put at 7.3mn boe, with first production expected in 1Q2005.*

Europe

The Norwegian Petroleum and Energy *Minister Thorhild Widvey has issued an invitation to oil companies to nominate blocks for Norway's 19th offshore licensing round. Companies have until 23 February 2005 to propose acreage which they want to see included in this round. Nominations are confined to areas of the Norwegian and Barents Seas already opened for exploration. Plans call for blocks to be put on offer next summer, and the government aims to award new licences in 1Q2006.*

The Alpha North gas and condensate *structure on Statoil's (49.5%) Sleipner West field in the North Sea began production on 11 October. Recoverable reserves in the satellite structure are put at about 13bn cm of gas and some 32mn barrels of condensate. Partners are ExxonMobil (32.34%), Total (9.41%) and Norsk Hydro (8.85%).*

The Norwegian Ministry of Petroleum *and Energy has approved the plan for development and operation (PDO) for*

NEWS Upstream

Green light for construction stage of ACG Phase 3

The construction stage of the Azeri, Chirag and Gunashli (ACG) phase 3 project development in the Azeri sector of the Caspian Sea has been sanctioned. Project partners are state-owned Socar (10%) and nine foreign oil companies – BP (operator, 34.1%), Unocal (10.3%), Inpex (10%), Statoil (8.6%), ExxonMobil (8%), TPAO (6.8%), Devon (5.6%), Itochu (3.9%) and Amerada Hess (2.7%).

The Phase 3 project is a $4.7bn development plan, some $3.2bn of which will be spent on the construction of facilities. The balance will be spent on predrilling subsea injection wells and platform development drilling during the production period. The project encompasses the development of the deepwater Gunashli portion of the ACG field. In addition, the design of Phase 3 will allow capture of potential reserves in the western portion of the Chirag area, which may not be accessed by the Chirag platform.

Phase 3 represents the next significant development phase of the ACG production sharing agreement (PSA) and will optimise full field development (FFD) economics enabling ACG production to rise to over 1mn b/d by 2009. Recoverable reserves for the deepwater Gunashli area of the ACG PSA are approximately 176mn tonnes (approximately 1.25bn barrels). The start of oil production from Phase 3 is currently planned for mid-2008 and will peak at around 300,000 b/d. All associated gas, except for fuel gas requirements, will be delivered to Socar.

The Phase 3 offshore facilities will comprise a 48-slot drilling, utilities and quarters (DUQ) platform bridge-linked to a production, compression, water injection and utilities (PCWU) platform in deepwater Gunashli, located in 175 metres of water. To provide early reservoir pressure support and a faster ramp up of the oil production rate, two subsea manifolds will be constructed with up to ten subsea water injection wells to be drilled prior to first oil.

Recoverable field reserves for ACG are estimated at around 730mn tonnes (5.4bn barrels) of oil. Overall the ACG field development will require seven offshore structures and over 400 wells, including Chirag and sidetracks.

First oil flowed from the Chirag field in November 1997, with production from Central Azeri on track to be delivered early 2005 and in 2006 and 2007 from West Azeri and East Azeri, respectively.

Review of US oil, gas and NGLs reserves

Proved reserves of US natural gas increased, albeit marginally, for the fifth year in a row, according to the *Advance Summary: US Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2003 Annual Report* published by the Energy Information Administration (EIA). US natural gas reserves increased by 1% in 2003. The majority of natural gas total discoveries were from extensions of existing conventional and unconventional gas fields. Reserves additions replaced 111% of 2003 gas production. Gas production remained almost level in 2003 as declines in the Gulf of Mexico and New Mexico were offset by production increases in the Rocky Mountain States and Texas.

Crude oil proved reserves declined 3% in 2003, the first decline in five years, as operators replaced only 58% of oil production with reserves additions. Total discoveries included significant new field discoveries in the Gulf of Mexico Federal Offshore, but proved reserves in several fields were lowered substantially because of poor well performance accompanied by engineering reassessments. US crude oil production remained almost level in 2003.

The Rocky Mountain States and Texas saw large gas reserves additions in 2003, driven by continuing development of unconventional gas fields, ie fields developed in tight sands, shales, and coalbeds. Significant reserves were added in the Powder River Basin (coalbed methane) and Green River Basin (deep and tight sand) in Wyoming, and in the Wattenberg field (tight sand) and San Juan Basin (coalbed methane) in Colorado and New Mexico. Significant reserves were also added in Texas' Newark East field (Barnett Shale) which is the US' sixth largest natural gas field.

Coalbed methane reserves increased 1% from 2002 and accounted for 10% of US dry gas proved reserves. Coalbed methane production declined very slightly in 2003 (less than 1%) and accounted for 8% of US dry gas production.

A copy of the report is available from the EIA website at **www.eia.doe.gov/oil_gas/fwd/adsum2003.html**

Prospects for UK gas supply and demand

A new study on *Prospects for UK Gas Supply and Demand* by Professor Alex Kemp and Linda Stephen, University of Aberdeen, has just been published. Key findings are that, while gas production from the UK Continental Shelf (UKCS) will continue its downward trend as UK demand continues to grow, the import schemes currently being seriously examined will ensure that in the medium and longer term, ample supplies will be available for the UK market.

On an annual basis the UK could become a net importer in 2005. By 2010, with a longer-term price scenario of \$20/b and 18 pence/therm, imports could be required to meet 25%–35% of total gas requirements, and by 2020 as much as 70%. If a long-term higher price scenario of \$25/b and 24 pence/therm prevailed, UK gas production would be higher and reliance on gas imports might be in the range 18%–33% in 2010 and 55%–65% in 2020. In the short-term, before the import schemes come onstream, the market situation will be quite tight, particularly in 2005, states the report.

The study also examined the peak winter demand/supply position. This involved the analysis of the effects of a typical January demand and a 1 in 20 winters peak demand. It also involved the examination of the contribution of gas from storage facilities (existing and proposed), and of the (changing) swing factor from production from the UKCS. Key findings are that the market will be tight in the winters of 2004/2005 and 2005/2006, but thereafter the imports and gas storage schemes should ensure that adequate supplies to meet peak demand are available.

Recent winters have been relatively mild and a problem would only emerge if much colder weather than that experienced in recent winters materialised. The study supports the view that wholesale gas prices will be relatively high over the next two winters, even if oil prices were to fall back from their present high levels. In the medium-term, however, the projected increases in import capacity along with UK production will have a major moderating influence on prices both on an annual and peak basis.

The report states that natural gas can readily play an increasing role in meeting the UK's energy requirements. Both indigenous production and imports are reasonably diversified, thereby enhancing the security of supply.

North Sea field of life extension plan

The UK Health and Safety Executive (HSE) accepted the 'Safety Case' submitted by Aker Kvaerner Operations, allowing the company as Duty Holder to continue to operate the AH001 installation.

Following the announcement, Aker Kvaerner launched its 'Field Life Extension Plan' – an ambitious scheme to extend the operational life of the Ivanhoe, Rob Roy, Renee and Rubie fields in the North Sea fields by three years – well beyond the previously anticipated shutdown date at the end of 2005 – whilst still seeking year-on-year improvements in health, safety and environmental performance. AH001 is located in UKCS block 15/21 on the Amerada Hess-operated Ivanhoe/Rob Roy field development. The installation also processes and exports oil from the Renee and Rubie fields, which are operated by Talisman. The Ivanhoe and Rob Roy fields were originally estimated to contain recoverable reserves of 88mn barrels and have a viable life expectancy of 10 years. However, they have already produced more than 180mn barrels over a 15-year period.

Simplifying cross-border field developments

The UK and Norwegian governments have agreed arrangements to pave the way for the development of two new North Sea fields – Boa and Playfair. The two fields have small extensions across the continental shelf boundary and previously would have been the subject of complex agreements between the UK and Norway on how they should be jointly regulated. However, the innovative approach being taken here for the first time will allow the fields to be regulated by the State with the majority field interest – considerably simplifying the process of bringing the fields into development.

The Playfair development is operated by CNR International, which is drilling a well from its Murchison platform and expects to begin production this autumn. The field lies almost entirely on the UK Continental Shelf, but with a small extension on to the Norwegian side. The Boa field is part of the Alvheim development, which is operated by Marathon. It is almost entirely on the Norwegian Continental Shelf, with a small extension into the UK area.

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the Alvheim field. Production is expected to start in early 2007 and reach a peak rate of 80,000 boe/d. Project partners are Marathon Oil (operator, 65%), ConocoPhillips (20%) and Lundin Petroleum (15%). The project will initially consist of developing the Kneler, Kameleon and Boa discoveries, as well as the previously undeveloped East Kameleon accumulation, via an FPSO with a subsea infrastructure comprising five drill centres and flowlines. The Alvheim field contains recoverable reserves of approximately 180mn boe. Recently, the Alvheim group reached agreement with Norsk Hydro to tie-in the nearby Klegg discovery. Additionally, the recent Hamsun discovery may be a potential tie-back to Alvheim.

Production commenced from Statoil's *Kvitebjørn field development in the Norwegian North Sea on 26 September. Daily output from the field is due to build up gradually to a plateau of about 20mn cm of natural gas and 62,000 barrels (10,000 cm) of condensate. Set to produce for 14 years, Kvitebjørn represents Statoil's first high temperature and pressure (HT/HP) project, with a reservoir pressure of 780 bar and a temperature of 150°C. Recoverable reserves are put at 55bn cm of gas and 190mn barrels of condensate.*

North America

The US Export-Import Bank has *approved a \$400mn long-term loan guarantee to support the sale of equipment and services by Nabors Industries of Houston and 166 other US suppliers – including Baker Hughes, Halliburton, Schlumberger and Landmark Graphics – to Pemex for the New Pidiregas Projects (NPP) in Mexico. NPP is made up of 23 natural gas and crude oil exploration and production sites located offshore in the Bay of Campeche off the northern coast of the Yucatan, and onshore in northern Veracruz and northwestern Tabasco. The goal of the projects is to increase Mexico's production capacity to 4mn b/d of oil and 7bn cf/d of gas by 2006.*

Middle East

Deputy Executive Chairman of the *Abu Dhabi National Oil Company (Adnoc) Abdullah bin Nasir Al Suwaidi is reported to have said that Adnoc and other companies in the group are planning a number of mega-projects*

In Brief

in order to increase oil and gas output in the near future. The UAE currently produces some 2.5mn b/d of oil. However, this will rise to 3mn b/d under the mega-project programme. Plans include increasing the production capacity of the Abu Dhabi Company for onshore oil operations (Adco) from the current ceiling of 1.2mn b/d to 1.4mn b/d, while Abu Dhabi's offshore oil output capacity will also be boosted from the current 470,000 b/d to 600,000 b/d by the Abu Dhabi Marine Operating Company (Adma-Opco).

Russia & Central Asia

***Total is to acquire a 25% stake plus** one share in Russian gas company Novatek. Novatek operates three gas fields in the Yamalo-Nenets region of Western Siberia – Tarkosale East, Khanchey and Yurkharov – with production of some 18bn cm in 2003. Proved and probable reserves for the fields are put at 4bn boe.*

***Lukoil-Western Siberia, a 100% sub**sidiary of Lukoil, is planning to spend around $300mn on development of the Bolshekhetskaya depression fields in Russia's Yamalo-Nenetsky Autonomous Region in 2005.*

***Elvari Neftegaz has completed the** drilling of its first exploration well under the Kaigansky–Vasukansky exploration licence in the south of the Sakhalin V area, offshore Sakhalin Island. The joint venture, 51% Rosneft and 49% BP, announced that the well encountered significant volumes of oil and gas in a number of high quality sandstone reservoirs.*

***DeGoyler & MacNaughton has put** West Siberia's total recoverable oil reserves at 200bn barrels, up from the original estimate of 100bn barrels. The consultant also believes that modern extraction technology could allow some 45% of reserves to be recovered.*

***Rosneft and Korea National Oil** Corporation are to jointly develop the Veninsky block (part of the Sakhalin-3 project) and a segment of the West Kamchatka shelf in the Sea of Okhotsk. Recoverable reserves for the Veninsky block are put at 51mn tonnes of oil, 37mn tonnes of gas condensate and 578bn cm of gas. The West Kamchatka shelf is estimated to hold some 900mn tonnes of hydrocarbons in some 26 'promising' structures.*

UK oil production falls again

UK oil production fell marginally again in July, to 1,762,238 b/d, down for the fifth consecutive month and more significantly down by 9.9% on the year, according to the latest Royal Bank of Scotland *Oil & Gas Index*. High oil prices continued to dominate the industry, with the monthly average price per barrel reaching $38.15. This, combined with strong growth in gas production, maintained UK oil and gas revenues.

Gas production of 10.854mn cf/d increased by 4.2% on the month and by 14.1% compared to June 2003. Combined oil and gas production of 3,673,127 boe/d increased by 1.1% on the year.

'The performance of the UK oil and gas industry is being held up by high oil prices and growth in gas production. However, we expect the pace of decline in UK oil production to slow as the global investment environment picks up through the rest of this year,' said Tony Wood, Senior Economist with the Royal Bank of Scotland Group.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Jul 2003	1,957,888	9,517	28.43
Aug	1,858,409	9,447	29.51
Sep	1,966,800	9,546	26.81
Oct	2,018,972	10,075	28.93
Nov	2,036,012	12,641	28.76
Dec	2,056,469	12,642	29.84
Jan 2004	2,014,906	12,689	31.12
Feb	1,972,891	11,220	30.89
Mar	2,006,160	11,787	33.72
Apr	1,964,905	12,181	33.36
May	1,778,979	9,218	37.72
Jun	1,776,246	10,413	35.21
Jul	1,762,238	10,854	38.15

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

BG Group signs agreement on Egyptian gas supply

BG Group has signed agreements with Egyptian General Petroleum Corporation (EGPC), Egyptian Natural Gas Holding Company (EGAS) and Petronas for the export of natural gas via the SEGAS LNG plant located in Damietta, Egypt. The gas supply will come from the BG-operated Scarab Saffron fields in the West Delta Deep Marine (WDDM) Concession, offshore the Nile Delta. Commencing in 1Q2005, BG Group and its upstream partners EGPC and Petronas will toll approximately 225mn cf/d of export gas through the SEGAS LNG plant for the first four years of the five-year contract and approximately 150mn cf/d in the final year.

In addition to the export gas, Scarab Saffron will continue to supply a minimum of 475mn cf/d to Egypt's domestic grid, lifting the contractual minimum Scarab Saffron offtake to 700mn cf/d. Two wells will be added at Scarab Saffron and the facilities are being de-bottlenecked to enable sustained supply at higher production rates. It is anticipated that once de-bottlenecking is completed early in 2005, Scarab Saffron facilities will be capable of delivering of 800mn cf/d.

Scarab Saffron is the first subsea development in Egypt. The facilities consist of eight subsea wells connected to a subsea manifold and, in turn, connected by 24-inch and 36-inch diameter pipelines to an onshore processing terminal. The fields are located approximately 90 km from the shore and in water depths of more than 700 metres.

In addition, BG Group – along with its partners in Egypt's Rosetta concession, Edison International and Shell – has reached agreement with Egyptian General Petroleum Corporation (EGPC) and Egyptian Natural Gas Holding Company (EGAS) to increase the Rosetta daily contracted quantity (DCQ) to 345mn cf/d from the current 275mn cf/d, effective during 2Q2005. Debottlenecking of the processing terminal will increase the facility capacity to 380mn cf/d.

Upstream development spend high, exploration low

Drawing on the findings of a recently published benchmarking study of the 10 largest quoted western oil and gas companies, Wood Mackenzie has found that development expenditure on upstream projects is at record highs, having risen from an aggregate of $34.6bn in 1998 to $49.5bn in 2003.

'This has been driven by expenditure on projects in the US Gulf of Mexico, deepwater West Africa and the Caspian, areas that saw significant exploration success in the 1990s,' explains Derek Butter, Head of Wood Mackenzie's Corporate Analysis team. 'We expect these high levels to be sustained over the period 2004–2006 on the basis of currently planned projects before dipping in 2007–2008.' This increased spending will translate into an upturn in production. We expect production from the top 10 companies, which account for 20% of the world's oil production, to increase on average by 3.5% per annum between 2003 and 2008.' This represents an increase of 4.5mn boe/d over the period in question.

According to Wood Mackenzie's research the upturn in development spending has not been matched by an increase in exploration spending by the same companies, which has fallen from over $11bn in 1998 to around $8bn in 2003. In relative terms, the fall has been even greater, with the average annual exploration spend per unit of production falling from $1.70/boe to $1/boe between 1998 and 2003. This is at a much lower level than the mid-cap peer group where relative spends have fallen from $2.80 to $2.50/boe.

The relative decline in exploration expenditure has coincided with a recent downturn in new discoveries. The average level of discoveries during the period 2001–2003 has been significantly lower than during the period 1997–2000.

'There are several reasons for the fall in exploration spend over this period,' Butter explains. 'The impact of the mega-mergers has delivered "cost synergies" by cutting exploration budgets. The rise in development spending has "squeezed out" exploration dollars as companies sought to reassure on financial discipline. There has been a decrease in spending in traditional mature areas, such as the North Sea, where results have been disappointing and not of a material scale for the larger companies. Finally, companies have switched their strategic focus to increase the importance of business development in areas such as unconventional oil and global gas as a source of replacing reserves.'

Going forward, Wood Mackenzie sees some evidence that exploration expenditures may rise, and in general, deepwater areas continue to deliver good results. However, for 'Big Oil', reserve replacement through exploration will continue to prove a challenge.

Apache closes ExxonMobil deals

Apache has closed on a series of previously announced agreements with ExxonMobil affiliates designed to optimise both companies' oil and gas exploration and development programmes in the US and Canada. The agreements provide for transfers and joint ventures/partnerships across a broad range of prospective and mature properties in the Permian Basin of West Texas and New Mexico, Western Canada, onshore Louisiana and the Gulf of Mexico Continental Shelf. Apache's participation includes cash payments of approximately $347mn.

In the Western Canadian Province of Alberta, Apache has signed a farm-in agreement covering ExxonMobil Canada Energy's interest in more than 380,000 gross acres of undeveloped properties in mature areas. Apache will drill at least 250 wells (operating the majority) over an initial two-year period with opportunity for further drilling.

In West Texas and New Mexico, the companies have formed a partnership under which Apache will participate in 23 mature producing oil and gas fields with production net to Apache of approximately 9,150 boe/d. ExxonMobil retains an interest in the production and a 50% working interest in all exploration acreage in depths below the currently producing intervals.

Onshore Louisiana and on Gulf of Mexico shelf acreage, Apache and ExxonMobil will jointly explore for deep gas on approximately 800,000 gross acres of Apache properties for an initial period of five years, with provisions for extension. Apache will continue to operate the shallower prospects, while ExxonMobil will operate the deeper prospects.

In Brief

Asia-Pacific

Cairn Energy has received formal *approval from the Indian for a declaration of commerciality in respect of the Mangala, N-A, Saraswati and Raageshwari discoveries. The Mangala and N-A fields are planned to start production in 4Q2007, producing up to 100,000 b/d.*

Reliance Industries and its Canadian *partner Niko Resources are reportedly planning to invest some $1bn on the staged development of their D6 deepwater gas reserves off the Andhra coast in India's Krishna Godavari Basin. First gas is slated for late 2006 or early 2007, at rate of 1bn cf. In-place gas reserves in the first 10 wells in D6 have been estimated at 11tn cf.*

Latin America

ChevronTexaco's Plataforma Deltana *Loran 2X exploration well – its first in block 2 offshore Venezuela – has encountered a 'significant amount' of natural gas. The well was tested at a rate in excess of 32mn cf/d from two sand intervals; both tests were equipment-restricted.*

Africa

ChevronTexaco (operator, 15%) and *partners have announced a significant discovery at the Lianzi-1 exploration well in the deepwater area between the Republics of Angola and Congo. The discovery, in the shared 14K/A-IMI Unit, is on the same stratigraphic trend as previous block 14 deepwater oil discoveries at Landana (1998) and Tombua (2001) in Angola. The Lianzi-1 exploration well flowed at a rate of more than 5,000 b/d of 40° API oil.*

First Calgary Petroleums has discovered *gas and condensate with its LEC-1 well on block 405b in Algeria. The well flowed 20,059 boe/d, comprising 105mn cf/d of gas and 2,602 b/d of condensate.*

Total (operator, 40%) has discovered *oil on its ultra-deep offshore permit Mer Tres Profonde Sud (MTPS), in water depths of near 2,000 metres offshore the Republic of Congo. The Pegase Nord Marine 1 well flowed at 14,360 b/d. Partners are ExxonMobil (30%) and Eni (30%).*

In Brief

UK

***Grain LNG, the National Gas Transco** subsidiary in charge of reviving the Isle of Grain LNG import terminal in the UK, has received local authority approval to more than triple capacity at the site. The facility is due to come onstream in 1Q2005 with an initial annual import capacity of 3.3mn tonnes. This can now be expanded to 10.5mn tonnes, with the new capacity likely to be available by the end of 2007.*

***Presenting its latest strategic review of** business operations, Shell warned that production is likely to remain fairly flat for the next five years – growing to between 3.8mn and 4mn boe/d by 2009 – as the group speeds its disposal of unwanted assets and rebuilds its reserves portfolio with a $15bn/y investment programme.*

Europe

***Total and Gaz de France (GdF) are to** terminate their long-standing contracts and separate their cross-shareholdings in Gaz du Sud-Ouest (GSO) and Compagne Francaise du Methane (CFM), their jointly-owned gas tranmission and supply subsidiaries in France. Total will become the sole shareholder in GSO, while GdF becomes the sole shareholder in CFM. Total will have access to a regasification capacity of 2.25bn cm in the planned Fos Cavaou terminal near Marseille. The LNG facility is due to be commissioned in 2007, with an initial capacity of 8.25bn cm.*

Eastern Europe

***OMV has increased its stake in** Hungarian oil and gas company Mol from 9% to 10%. The company has also signed an agreement to sell the 25.1% it holds in the Rompetrol Group to Rompetrol Holding, a Swiss-based holding company that is owned by Rompetrol's senior managers.*

North America

***cc-hubwoo, a leading European** provider for on-demand electronic procurement solutions and MRO supplier network management, reports that it is engaged in exclusive discussions with Trade-Ranger™, the electronic marketplace specialising in providing e-procurement solutions for the oil, gas and*

NEWS Industry

Latest UK energy trends published

The UK Department of Trade and Industry recently published its latest *Energy Trends* and *Quarterly Energy Prices* surveys.

The reports indicate that indigenous production of primary fuels was 60mn tonnes of oil equivalent (toe) in 2Q2004, 5% lower than in 2Q2003. Final energy consumption in 2Q2004 was 0.4% higher than in 2Q2003.

On seasonally adjusted and temperature corrected annualised rates, total inland consumption on a primary fuel input basis was 235.5mn toe in 2Q2004, 0.8% lower than the same quarter in 2003. Between the two quarters coal and other solid fuel consumption fell by 10.4%, oil consumption increased by 1.4%, gas consumption rose by 3.9% and primary electricity consumption decreased by 9%.

Total indigenous UK production of crude oil and NGLs in 2Q2004 decreased by 6.3% compared with 2003 to 24.4mn tonnes. Only four new fields started production after June 2003 and output from these fields was insufficient to make up for the general decline in production from older established fields. The UK retained its position as a net exporter of oil and oil products. Exports of petroleum products rose by 0.4% and imports rose by 8.2%. Overall primary demand for oil products in 2Q2004 was 10% higher than last year. Deliveries of unleaded motor spirit fell by 6.4%, while deliveries of Derv fuel and aviation turbine fuel increased by 6.7% and 3.6% respectively.

Total indigenous UK production of natural gas in 2Q2004 was 0.6% lower than in the corresponding quarter a year earlier. Compared with 2Q2003, exports of natural gas in the second quarter of 2004 decreased by 27.1% while imports increased by 27%. Net exports of gas at 29.0 TWh were 4.2% lower than in 2Q2003. Demand for gas in 2Q2004 was 8.4% higher than the level in 2Q2003. Gas use for electricity generation was 14.6% higher than in 2Q2003, with gas prices falling slightly and coal prices rising. Provisionally, consumption in the domestic sector rose by 9.4%. In the industrial sector gas sales were provisionally 4.4% lower than in 2Q2003, while in the services sector consumption rose by 8.9%.

Energy Trends and the *Quarterly Energy Prices* bulletins, published quarterly, are available on the Internet at **www.dti.gov.uk/energy/inform/energy_stats_overview/index.shtml**

Conoco buys 7.59% stake in Lukoil

ConocoPhillips has acquired the Russian government's 7.59% stake in Lukoil for $1.988bn.

In addition, Lukoil and ConocoPhillips have created a joint venture with respective interests of 70% and 30% that will allow ConocoPhillips to partner in the development of Lukoil's reserves in the northern Timan-Pechora area of Russia. Under the terms of the agreement, ConocoPhillips will pay Lukoil in excess of $370mn. The joint venture will be governed 50:50 by the two companies and is expected to be producing and marketing approximately 200,000 b/d of oil by 2008.

Shipping sector guidance from ABS

With contracts pending for an entirely new generation of very large LNG carriers of 200,000 cm and above, ABS is providing guidance to owners and shipyards on a range of issues that will affect the selection of the propulsion system for these advanced vessels. The ABS Guide for Design and Installation of Dual Fuel Engines (publication #112) is available for download from the ABS website at **www.eagle.org/rules/downloads/112-dualfuel.pdf**

ABS has also produced technical guidance for inert gas systems for ballast tanks. Compliance to the guidelines leads to the class notation IGS-Ballast. ABS claims to be the first classification society to set standards and offer a notation for complying with design criteria and procedures for inerting ballast tanks on double hull tankers. A copy of the ABS Guide for Inert Gas System for Ballast Tanks is available for download from the ABS website in the 'Rules & Guides' section at **www.eagle.org/rules/downloads/131-IGS.pdf**

Meanwhile, ABS has launched a campaign to assist owners of vessels subject to Marpol Annex VI obtain the required International Air Pollution Prevention Certificate (IAPPC). An overview of Annex VI is available for download from the ABS website at **www.eagle.org/regulatory/noxsoxpaperaug04.pdf** Readers should also refer to the 'Marine Environment/Air Pollution' section of the IMO website at **www.imo.org/home.asp** for IMO's overview of Annex VI.

BP agrees LNG supply to Marathon

BP is to supply Marathon Oil with 58bn cf/y of LNG for a minimum period of five years beginning in mid-2005. Marathon will take delivery at the Elba Island, Georgia, LNG regasification terminal. Pricing of the LNG will be linked to the Henry Hub Index. Marathon's rights to deliver and sell LNG at the Elba Island terminal were acquired in late 2002 for a period of up to 22 years. This year Marathon has received three cargoes of LNG utilising its Elba Island delivery rights. The company is continuing to actively seek additional cargoes prior to the start of deliveries from BP.

Other key integrated gas activities include the company's Equatorial Guinea LNG project in which Marathon and its partner, Compania Nacional de Petroleos de Guinea Ecuatorial (GEPetrol), the national oil company of Equatorial Guinea, recently announced that they had reached the final investment decision for this key project. Construction of the $1.4bn Equatorial Guinea LNG project, in which Marathon currently holds a 75% interest, is underway with shipment of the first cargoes of LNG expected to begin in late 2007. This project is expected to be one of the lowest cost LNG operations in the Atlantic Basin, with an all-in LNG operating, capital and feedstock cost of approximately $1/mn Btu at the loading flange of the LNG plant.

Under the terms of a 17-year purchase and sale agreement, 3.4mn t/y of LNG from the Equatorial Guinea LNG plant will be sold to British Gas (BG), beginning in late 2007. The LNG will be purchased on a free on board (FOB) basis at Bioko Island, Equatorial Guinea, with pricing linked principally to the Henry Hub index. BG intends to target the Lake Charles (Louisiana) import terminal as the primary destination for the LNG; however, the agreement provides destination flexibility for the LNG, enabling BG to take advantage of prevailing market conditions at other import destinations around the world. Efforts are currently underway to expand the utilisation of this LNG facility above and beyond the contract to supply 3.4mn t/y. Marathon also is seeking additional natural gas supply in the area that could lead to the development of a second LNG train.

Latest news from the European Commission

The European Commission under incoming Energy Commissioner Lázló Kovács could look to Russia and the Ukraine as the key guarantors of Europe's future gas and oil supplies, writes *Keith Nuthall*. Kovács, a Hungarian, has told the European Parliament that he intends to establish 'real cooperation' with these countries as a first priority. He added that, after assuming office in November, he might propose improving third-party access to gas networks. And Kovács hinted he would continue pushing ministers to accept a system of EU countries sharing oil stocks in a crisis, despite their resistance to the idea.

Meanwhile, incoming EU Transport Commissioner Jacques Barrot has called for loosening of an exemption of air fuel from taxation, currently guaranteed by international treaties. Barrot suggested a fuel tax could be imposed for flights between EU countries.

In other EU news:

- EU ministers have been asked to allow France to give powers to its regional governments, enabling them to reduce duties on unleaded petrol and gas oil sold in their regions. Cuts could not exceed €35.4 and €23 per 1,000 litres respectively, however.
- The European Court of Justice (ECJ) has decided EU member states cannot impose extra excise duty on petrol and diesel bought in another EU country by a commercial vehicle. This rule would apply where a vehicle was driven across a border, or the fuel was used for a different purpose in another EU country, such as agricultural work.
- The ECJ has also ruled that service station operators must take responsibility for oil and petrol leaks, unless they can demonstrate that the pollution is the fault of the oil company supplying their fuel.
- The European Investment Bank is to lend Italy's ERG up to €175mn to fund the environmental upgrading and integration of two coastal refineries at Priolo Gargallo, Sicily.
- The 10 eastern and southern European countries joining the EU in May are to join the 2003 Protocol to the International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage, widening their compensation liability for spill damage.
- The EC has approved the acquisition of Spainish utility company Hidrocantábrico by Portuguese electricity company EDP. Hidrocantábrico supplies gas to northern Spain.
- The European Free Trade Area (EFTA) of Switzerland, Norway, Iceland and Liechtenstein, and the Gulf Cooperation Council are to launch high-level meetings of officials next year aimed at forging a free trade deal.

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chemicals industries, with a view to creating one of the world's largest electronic trading and catalogue content hubs for indirect materials. cc-hubwoo plans to acquire 100% control of Trade-Ranger™ for a consideration that includes both cc-hubwoo stock and cash. The expected value of the transaction is between $12mn and $23mn.

Russia & Central Asia

***Sakhalin Energy Investment Company** has signed an agreement to supply 37mn tonnes of LNG over a 20-year period to Shell Eastern Trading for the North American natural gas market. The agreement represents the first sales of Russian gas to North America, states Shell. The LNG will supply the new Energia Costa Azul plant that will be constructed in Baja California, Mexico. The agreement calls for significantly higher volumes of LNG deliveries during the first three years, with a plateau supply of 1.6mn t/y (approximately 0.2bn cf/d). First deliveries are expected early 2008.*

***Gazprom has announced that its first** LNG export facility will be sited at Ust-Luga on the Gulf of Finland. Export capacity will be between 3mn and 5mn t/y. The liquefaction plant will utilise gas from Gazprom's Shtokman field, which is due to enter production in 2006.*

Asia-Pacific

***BP and its partners in the Tangguh** LNG project in Indonesia have signed a long-term agreement with Sempra Energy for the supply of up to 3.7mn t/y of LNG to the proposed receiving terminal in Baja California, Mexico. This agreement covers half of Sempra's design capacity. The contract runs for 20 years from 2008.*

Africa

***The Western Libya gas project – which** includes Greenstream, the longest subsea pipeline in the Mediterranean – has been officially inaugurated. Gas produced from the Wafa field in the desert and Bahr Essalam, offshore, is sent to Mellitah and then transported to Italy through the Greenstream pipeline. The project was launched by partners Eni and state-owned NOC in 1999 and was completed on schedule for an investment of around €7bn. Greenstream will carry some 8bn cm/y of natural gas to Italy.*

In Brief

UK

Centrica has completed the sale of the *AA (Automobile Association) to a company formed by CVC Capital Partners and Permira Advisers as announced on 1 July 2004. The intention is to return a total of not less than £1.5bn to shareholders via a combination of the proposed special dividend and a rolling share repurchase programme which is already underway, comments Centrica.*

In a time of highly volatile oil prices, *IPE is introducing a new energy quote service under the name IPETXTME. The service provides the user with up to eight different oil and gas prices on his/her mobile phone. IPETXTME offers nationwide coverage on all four GSM mobile networks.*

Kuwait Petroleum (GB) (KPGB) has *sold its Ross Chemicals & Storage Company storage terminal at Grangemouth in Scotland to Kaneb Terminals for an undisclosed sum.*

Europe

Total has created a new legal entity, *Arkema, as part of its plan to create a new chemicals business organisation. The chemicals division now comprises a total of three business units: Total Petrochemicals – covering all petrochemical operations and fertilisers; Specialities – combining Hutchinson (rubber processing), Bostik (adhesives), Cray Valley and Sartomer (resins) and Atotech (electroplating); and Arkema – a new units destined to be independent, encompassing vinyl products, industrial chemicals and performance products.*

Repsol YPF is to acquire Borealis' *petrochemicals site at Sines, Portugal, for an undisclosed sum. According to Repsol YPF, the acquisition will increase its cracker production capacity by 38% and allow it to develop in two core businesses – olefins/base petrochemicals and polyolefins.*

The Norwegian government has pro- *posed a cut in duty on sulphur-free fuels in a bid to encourage their uptake. The government proposes to increase fuel tax by NKr0.02–0.03 per litre on existing grades of petrol and diesel oil, while reducing it by NKr0.02 for sulphur-free types. A European Union directive requires automotive*

Ofgem reports on UK wholesale gas prices in 2003 and 2004

After nearly a year-long investigation, UK energy regulator Ofgem has reported on the record UK wholesale gas prices in October 2003 and the summer of 2004. Amid allegations of deliberate price manipulation amongst traders, the report concluded that supply issues and oil price linkage were the key factors causing the price spikes, although investigations into contractual issues are still ongoing.

During the final quarter of 2003, wholesale gas prices reached then unprecedented levels. Prices for day-ahead contracts peaked at more than 34 pence per therm (p/therm) and averaged 25.2 p/therm during October and November 2003, more than 42% higher than the same period in 2002. During the month of October, the price of the November contract increased by 29%. More recently, the 12.4% retail price rises levied by British Gas in August of this year, and subsequently repeated by a number of other suppliers, were attributed to wholesale market conditions.

The Ofgem report identifies two main causes for the price spikes:

- The effect of oil product price linkage on UK gas contracts. Although the majority of gas supply contracts in the UK are priced on a market linked basis (and have been since the advent of liberalisation in the UK), prices were affected by the fact that gas imports from continental Europe arriving through the Interconnector pipeline are mainly oil product price linked. With upward movement in continental gas prices caused by pressure on oil prices, an upward effect was consequently passed through to UK gas.
- The production plateau in UK gas is causing a greater need for more expensive imported gas. The effect of this already declining production was exacerbated in 3Q2003 by various scheduled and unscheduled maintenance projects on North Sea fields.

These record price spikes were not confined to 2003. More recently gas prices have averaged 25.9 p/therm during August and September (traditionally a period when low demand causes prices to fall), some 85% higher than the same period last year. Similarly, prices for the forward winter contract have recently been trading around the 42 p/therm level, some 69% higher than at this time last year. With this in mind, Ofgem recently decided to widen its investigation to include the more recent price spikes.

However, the issue of possible market manipulation remains unresolved and Ofgem has stated its intention to continue investigating why some 4% of supply that was physically available was not brought to market, a move that would have eased the price spikes. The results of this investigation are expected to focus on the terms of the contracts held by BP, Shell, Centrica, ExxonMobil, Total, Amerada Hess and Perenco. Ofgem will also work with the Competition Directorate of the European Commission and national regulators to determine if there have been any breaches of competition law.

Shell sells various US pipeline assets

Shell Oil Products has completed the sale of its Mid-Continent refined products pipeline system to Magellan Midstream Partners, and the sale of the company's Midwest refined products pipeline system to Buckeye Partners for a combined total of just over $1bn.

The Mid-Continent refined products pipeline system, being acquired by Magellan Midstream Partners for $490mn, is comprised of pipeline and storage assets located in Texas, Oklahoma, Kansas and Colorado. Major assets in the system include the Orion, Hearne, Chase and Cimarron pipelines, which, along with associated distribution terminal and storage assets, form an integrated system that carries refined products from the US Gulf Coast refineries to West Texas and the Great Plains region. Major markets include Dallas, El Paso, and Denver.

The Midwest refined products pipeline system, being acquired by Buckeye Partners for $517mn, is comprised of pipeline and storage assets located in Illinois, Indiana, Ohio, Michigan and Wisconsin. Major assets included in the sale consist of the East Line, North Line, St Louis ATF, St Louis 6-inch and the 2Rivers pipelines. These pipeline assets, along with 24 distribution terminal assets, form an integrated system that carries refined products from primarily US Mid-Continent refineries to points throughout the Midwest region. Major markets include Chicago, St Louis, Cleveland, Indianapolis and Cincinnati.

New alliance to boost UK biodiesel

Global Commodities UK, manufacturer of biodiesel, and Centaur Grain, a UK-based grain marketing organisation, have entered into an alliance that they claim will enable British farmers to play a key role in the production of biodiesel. Global Commodities currently manufactures 12mn l/y of biodiesel from recovered vegetable oil at its purpose-built plant at Shipdham, Norfolk, reportedly the first of its type in the UK. Plans are underway for a new facility that will incorporate a crushing plant and will produce in excess of 180mn l/y. Centaur Grain markets over 1,500,000 tonnes of grains, oilseeds and pulses produced annually by more than 1,300 farmer members in an area from the Scottish Borders to the Isle of Wight. The company, which will act as sole supplier of UK oilseed rape to Global Commodities' new plant, is now approaching members with Energy Rape contracts for the 2005 harvest.

Major energy buyers encouraged to go 'all in'

Recent research from market analyst Datamonitor has revealed that between 10% and 20% of UK industrial and commercial (I&C) customers are willing to buy energy under contracts that fully integrate commodity supply of power and gas with 'added-value' demand-management services. Performance Partnerships – a new marketing initiative from London Energy (a subsidiary of Electricité de France, EdF) and Dalkia UK – aims to corner this niche segment with a product that overcomes some of the usual reservations about 'added-value' services.

Datamonitor Utilities Analyst and report author Mikhail Masokin says utility outsourcing could rival the IT outsourcing market in a few years' time, but it is currently suffering from considerable barriers to higher take-up. 'Added-value' demand-management services are an attractive growth market for companies in the energy sector, with a potential for 25% annual growth rates and double-digit profit margins. However, service providers find it difficult to win customers and secure deals, as benefits are difficult to quantify and pay-back periods can be viewed as too long, he explains. 'In particular, demonstrating return on investment is difficult, both by service providers to energy buyers and by energy buyers themselves to their companies' decision makers.'

Even where benefits can be clearly demonstrated, raising the finance can be difficult as most companies operate on thin margins. Masokin comments: 'The internal structures of would-be customers are often not amenable to buying in energy services, due to conflicts of interest between energy buyers and chief financial officers.'

The new Performance Partnerships initiative from Dalkia UK and London Energy is an attempt to overcome this and other obstacles to greater take-up, by combining energy supply and demand-management services into a fully integrated proposition. However, the potential for Performance Partnership-type packages is limited in the UK, although the Continent may prove to be a promising market for integrated deals.

According to Masokin: 'Datamonitor believes that by the end of 2005 some 15 UK customers spending some £1mn/y on energy and energy-related services could be on a Performance Partnership deal. However, the long-term prospects for integrated deals are modest in the UK, as large UK customers, who are currently the main target for the initiative, are generally averse to the idea of integrated deals. Many of them have the capacity to manage energy demand in-house. Most of those who are receptive to the concept will have been signed up during the pilot stage, limiting the scope for further growth and making this a niche offering for both partners.'

However, according to Datamonitor research, there is already significant unmet demand for integrated deals at the larger end of continental I&C markets, with users accustomed to free or cheap added-value services from former incumbents. 'That said, fulfilment would be more difficult in markets with limited wholesale liquidity,' Masokin comments. 'Generally, in mature markets like the UK the general trend will be towards value chain disaggregation, although there will always be users bucking the trend. In our opinion, they constitute between 10% and 20% of the partnership's target customer base. Nevertheless, if London Energy and Dalkia corner this niche segment, they will have significantly boosted their overall market share, as well as improving profitability.'

'For other companies to successfully replicate the Performance Partnerships concept, both potential partners should have the capability and high brand recognition in both areas (commodity energy supply and added-value energy services). Currently, the only candidates are RWE, which has long followed a bundled services model in its core German market, and Belgium's Electrabel in partnership with its sister company Elyo.'

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fuels containing virtually no sulphur to be phased in from next year, with all petrol and diesel oil meeting this criterion by 2009.

***Statkraft and Norsk Hydro are to** progress their 50:50 Naturkraft joint venture's plans to build a gas-fired power plant at Karsto. The 400-MW facility will produce some 3 TWh per year when at full capacity utilisation – increasing Norwegian electricity supplies by some 2.5% and reducing the need for imported power. The plant is due to be commissioned in 2007.*

Eastern Europe

***BP has sold its Czech Republic LPG business** to a subsidiary of the UGI Corporation, Flaga Plyn. The sale, which includes the LPG filling plant and storage depot in Dysina together with several bottle distribution centres and assets at customer sites, will have no impact on the other BP business activities in the Czech Republic.*

Asia-Pacific

***Total (49%) and Sinochem (51%) are** to set up a network of 200 service stations in northern China at a cost of some $120mn.*

***Petronas is embarking on a development** of a new world scale methanol plant adjacent to its existing methanol plant in Labuan, Malaysia. The new plant is scheduled to commence operations by the end of 2007 and will have a production capacity of 1.7mn t/y (or 5,000 t/d). Feedstock of about 150mn cf/d of gas will be supplied from the gas fields offshore Sabah. Methanol produced from the new plant will be supplied to the domestic market as well the growing markets in Southeast Asia, North East Asia and India.*

***Santos is reported to have signed a** second gas sales contract for the John Brookes gas field in exploration permit WA 214-P in the Carnarvon Basin offshore Western Australia. Under the contract, Santos (45%) and Apache (55%, operator) will supply EDL (Energy Developments Ltd) LNG with 58 petajoules (PJ) of gas over 20 years. EDL will use the gas to supply four gas-fired power stations under construction as part of its West Kimberley power project. The electricity produced is to be sold under a recently executed power purchase agreement*

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with Western Power Corporation. Under the contract, which will commence in 1H2006, the initial supply commitment is 6 terajoules per day (TJ/d) and will then increase over the life of the contract to 9 TJ/d. Santos and Apache also have the opportunity to increase daily contract quantities in the future subject to gas availability and their consent.

Africa

***Many shops and offices in Nigeria's** main cities of Abuja and Lagos closed on 11 October at the start of a four-day general strike over fuel price rises in what is Africa's largest oil producing nation. Fuel subsidies were removed last year, leading to a 25% hike in the price of petrol. Oil production has not been affected – however, in London, prices of Brent crude oil passed the $50/b mark for the first time. President Olusegun Obasanjo has set up a task force to look at the effects of the fuel price rises in a bid to calm mounting tensions. The task force includes the leader of Nigeria's trade union umbrella group, Adams Oshiomhole.*

World

***The Organisation for Economic** Cooperation and Development (OECD) has unusually recommended government intervention to kick-start a new fuel sector, namely biofuels, reports* Keith Nuthall. *It says governments should encourage technical innovation to narrow the price gap with oil and gas products, seeding future free market demand.*

NEWS Downstream

DCC acquires Shell Direct UK business

Shell is to sell its Shell Direct UK operation, which supplies heating oils and transport fuels to domestic, agricultural and small commercial and industrial customers in Britain, to DCC Energy for £13.75mn (€20.13mn). The business, which will operate as a Shell-branded distributor trading as Emo Oil, operates from 36 depots across Britain, selling some 600mn l/y of fuel. The acquisition builds upon DCC's acquisition in 2001 of BP's oil marketing and distribution business in Scotland. DCC will now have sales volumes of approximately 1.1bn litres in Britain and will become the largest independent oil marketing and distribution business in the British market.

DCC Energy has also built a strong nationwide business in the sale and marketing of LPG (propane and butane) in Britain following a period of strong organic growth and a number of acquisitions. These acquisitions culminated with the purchase of the British Gas LPG business from Centrica in 2002 which positioned DCC as the second largest LPG sales and marketing business in Britain, with a market share of approximately 21%.

D1 Oils to float on UK stock exchange

D1 Oils is intending to float on the London Stock Exchange in order to raise £20mn. The company is involved in the global production of biodiesel from crops in the developing world and has projects underway in South Africa, West Africa, India and elsewhere in the Asia-Pacific to produce this green fuel for local use and export.

One of the most promising production sources of biodiesel identified by D1 is reported to be the *Jatropha Curcas*, a multi-purpose and drought resistant shrub or small tree. 'More than 40% of the energy in the fruit of the *Jatropha* can be extracted as oil that has similar energy value to diesel and can be blended with mineral diesel,' explains the company. '*Jatropha* is easy to establish and grows relatively quickly. Being both hardy and drought tolerant, the tree can be used to reclaim waste lands, and grown on fallow, along railway tracks and roads or as boundary fences. In irrigated areas it can be grown with much higher yields.'

D1 also predicts that *Jatropha* cultivation will bring significant environmental developments, as the tree can grow on waste, marginal and arid land.

D1 also plans to play a major role in developing biodiesel in India, where the government has introduced a $200mn biofuels programme to replace 5% of current domestic diesel usage with biodiesel by 2005/2006.

UK Deliveries into Consumption (tonnes)

Products	†Aug 2003	†Aug 2004	†Jan–Aug 2003	†Jan–Aug 2004	% Change
Naphtha/LDF	168,900	174,537	1,501,413	1,534,326	2
ATF – Kerosene	899,676	991,078	6,660,011	6,998,035	5
Petrol	–	–	–	–	–
of which unleaded	1,542,098	1,612,706	12,446,989	12,754,109	2
of which Super unleaded	69,228	74,766	541,917	577,842	7
ULSP (ultra low sulphur petrol)	1,472,870	1,537,940	11,905,072	12,176,267	2
Lead Replacement Petrol (LRP)	13,382	3,904	146,591	48,704	–67
Burning Oil	143,798	252,662	2,719,533	2,796,253	3
Automotive Diesel	1,344,581	1,533,753	11,190,882	12,491,449	12
Gas/Diesel Oil	457,273	511,187	4,086,070	4,191,228	3
Fuel Oil	181,638	259,180	1,571,299	1,609,969	2
Lubricating Oil	69,414	56,917	559,546	503,615	–10
Other Products	680,038	709,441	5,407,464	6,641,741	23
Total above	5,500,799	6,105,364	46,516,666	49,569,428	7
Refinery Consumption	387,703	483,178	3,154,800	3,564,545	13
Total all products	5,888,502	6,588,542	49,671,466	52,656,900	6

† Revised with adjustments

All figures provided by the UK Department of Trade and Industry (DTI), as supplied by reporting companies

Photo: ConocoPhillips

Kazakh government discourages Caspian exploration

Fears that high oil prices and pressure for new supply would lead to producer governments tightening the financial terms and conditions against the international oil companies appear to be coming about, reports *Christopher Pala* in Kazakhstan.

Kazakhstan's North Caspian is home to Kashagan, claimed to be the world's fifth-largest oil field with estimated recoverable reserves of between 9bn and 12bn barrels. The surrounding area is also believed likely to yield the same amount of oil – some 1mn b/d.

The region is generally believed to be one of the last places on earth that are geologically attractive, politically accessible and where major discoveries can still be made. However, exploration there doesn't come cheap. Kashagan's first well – a hit, just like its five successors – cost $1bn. Indeed, new legislation is reported to be making it so unattractive to invest in the North Caspian's 100-odd undeveloped blocks, that foreign oil companies – the only ones with the know-how and the capital to drill in some of the most challenging conditions in the world – are shying away from investing any money.

Bad news

A new amendment to the Kazakh tax code law, which came in to effect this year, increases the government take to between 65% and 85%. It also eliminates, for new contracts, the traditional tax-stability clause. As a result, maximum rates of return are now calculated to be below 10%.

In an extended interview during the Kazakhstan International Oil and Gas Exhibition in October, Martin Ferstl, Chairman of Shell Kazakhstan, a Kashagan partner, said the contracts signed during the 1990s were 'adequate for the risks that that were taken'. He continued: 'Now Kazakhstan is saying we have proven the potential of the Caspian Sea and now it is time to toughen up the terms of fiscal legislation. But the problem is the terms were overshot. They are on the tough end of the scale of international comparison. A rate of return below 10% is not enough to justify the exploration risk, the development risk, the market risk and the transportation risk. There has to be 15% or more.'

Appraisal work under way at the Kashagan field, Kazakhstan

Furthermore, a new law on production sharing agreements (PSAs) that seems likely to pass before the end of the year gives the government first right of preemption when a consortium member seeks to sell its shareholding. Marla Valdez, Managing Partner of the law firm Denton Wilde Sapte in Almaty, said such a clause would apply to existing contracts, including Kashagan and Karachaganak, the country's third-largest field. 'It's virtually unprecedented in other jurisdictions,' she said.

She and others say the law appears to be designed to give a legal basis to a government effort to buy a one-sixth share of Kashagan currently held by BG Group. BG announced in March 2003 that it would sell its share to two state Chinese oil companies for $1.23bn. However, as expected, five of the other partners – Agip (the operator), ExxonMobil, Shell and Total, each with a sixth share; and ConocoPhilips – exercised their pre-emption right in order to bring down the number of partners and make decision-making smoother. Inpex of Japan, which split the last sixth with ConocoPhillips, did not pre-empt.

The Kazakh government waited until early this year – nearly a year after BG disclosed its intention to sell – before announcing that it wanted the share for itself. The rest of the partners objected, saying the PSA specifies that only the partners have a right to pre-empt. Since then, there has been a standoff.

At stake is not only the question of what kind of partner KazMunaigas – the state oil company run by President Nursultan Nazarbayev's son-in-law, Timur Kulibayev – would be in the world's most expensive oil field development project (the final tab is expected to be close to $30bn), but also whether Kazakhstan would be willing to contribute its portion of the colossal investment.

A window on just how willing Kazakhstan's government is willing to put in its fair share came two years ago, when it refused to pay a 20% contribution – commensurate with its 20% share – in the $4.4bn expansion of the country's largest oil field, Tengiz. KMG demanded that the other partners in the joint venture (which include ChevronTexaco 50%, ExxonMobil 20% and LukArko 5%) should borrow its share and pay the interest. After the consortium shut down the project for five months, the government agreed to pay the interest as long as the partners provided the financing, at a rate lower than the government would have obtained on its own.

Energy Minister Vladimir Shkolnik insists Kazakhstan has a right to its own resources. Agip is known to be the most accommodating of the partners, while Shell and ExxonMobil have registered their strong opposition to any forced buyout. As for BG, spokeswoman Petrina Fahey denied widespread reports that the former British gas monopoly, however overexposed it may be in Kazakhstan with its share in the Karachaganak condensate field, has decided to hang on to its share for the moment. She said BG was still trying to make the sale to its partners and would be obliged to make an announcement if it changed this position.

Paying the price

For BG, which is believed to have spent some $400mn on the project since the sale price of $1.23bn was announced 18 months ago, there is the additional consideration that with all of Kashagan's six test wells being successful, the market value of its share has risen beyond the money spent – to a total the government may not be willing to pay.

Also, the price was set during a bitter dispute between the consortium and the partners over a fine imposed for a one-year delay in drilling the first well. The negotiations over the fine – which was reduced to $150mn from an initial demand of close to $1bn – dragged on for a year and a half and, ironically, resulted in first commercial production being planned for 2008 instead of 2006, as could have been achieved even after taking into account the original one-year delay.

This year, the development plan was finally approved. Consortium members say the dispute over BG is not preventing the project from moving ahead, with more than \$3bn expected to be spent in 2005, compared with \$1.8bn this year.

Tug of war

The outcome of the tug of war over the BG shares remains hard to predict, with each side seemingly unwilling to budge. Energy Minister Shkolnik and Shell's Ferstl have separately said they expected the dispute to be resolved amicably, while Shkolnik emphasised that a mutually agreeable solution would still give KMG the sought-after shareholding.

Still, experts say enshrining a government right of pre-emption would devalue assets, particularly since the government could change the terms of payment at will.

Kazakhstan's Russian-style attempt to improve its terms and control of major projects has wide political support among the country's 15mn people, many of whom view foreign oil companies as rapacious thieves bent on stealing the motherland's riches. Government officials say – and popular opinion largely agrees – that the early deals that opened Tengiz, Kashagan, Karachaganak and Kumkol to foreign investors gave these investors advantages that were commensurate to the risks they were taking. But now, they say, Kazakhstan boasts the soundest monetary and financial system in the former Soviet Union, Baltics apart, and an average growth rate of 10%/y for the past five years. Moreover, the Caspian has proven as rich in oil as previously hoped, so they say the time has come to improve the terms.

But not all agree as to just how high the bar can be raised before achieving the current stay-away effect. Lyazzat Kiinov, the Deputy Energy Minister, said in an interview that his Ministry had opposed the new tax code, but had been overridden by other parts of the Nazarbayev administration. 'The people making the law are not the people in the oil business,' one veteran oil man said. Kiinov added: 'We still hope some of these clauses can be removed by the end of the year.'

Others are not so sure, however. Analyst Laurent Ruseckas of the Eurasia group notes that with \$50/b prices, Kazakhstan's relatively small economy is awash in cash from its current exports of 1mn b/d – set to triple by 2015 and perhaps plateau at 4mn b/d, making it one of the world's top five exporters. 'Whether the blocks start producing in 2012 or 2016 doesn't matter much to them,' he said.

On the contrary, there is an incentive to wait, Ruseckas said. 'In 10 years, maybe they can do it themselves. That's what Yukos and Sibneft did. It's called the Russian oil miracle, production increased 3.4mn b/d in five years because of Russian companies using Western contractors and technology.'

Kazakhstan is also moving at an appropriate pace to find ways of bringing its light crude to market, analysts say. In September, construction began on a pipeline to the Chinese border with an initial capacity of 20mn t/y (approx 400,000 b/d).

Dr Ferstl of Shell said Kashagan's initial production will be absorbed by existing pipelines and by barging the oil across the Caspian from Aktau, Kazakhstan, to Baku, Azerbaijan. But by 2008, major financial commitments will have to be made to create new routes, and 'the time to start examining all the options is now'.

Jury is still out

'The jury is still out on whether all these obstacles will delay Kazakhstan's production,' said Richard Vierbuchen, ExxonMobil's Vice President for the Caspian and the Middle East. 'There is still time to make adjustments.'

Gas is key to meeting rising regional energy demand

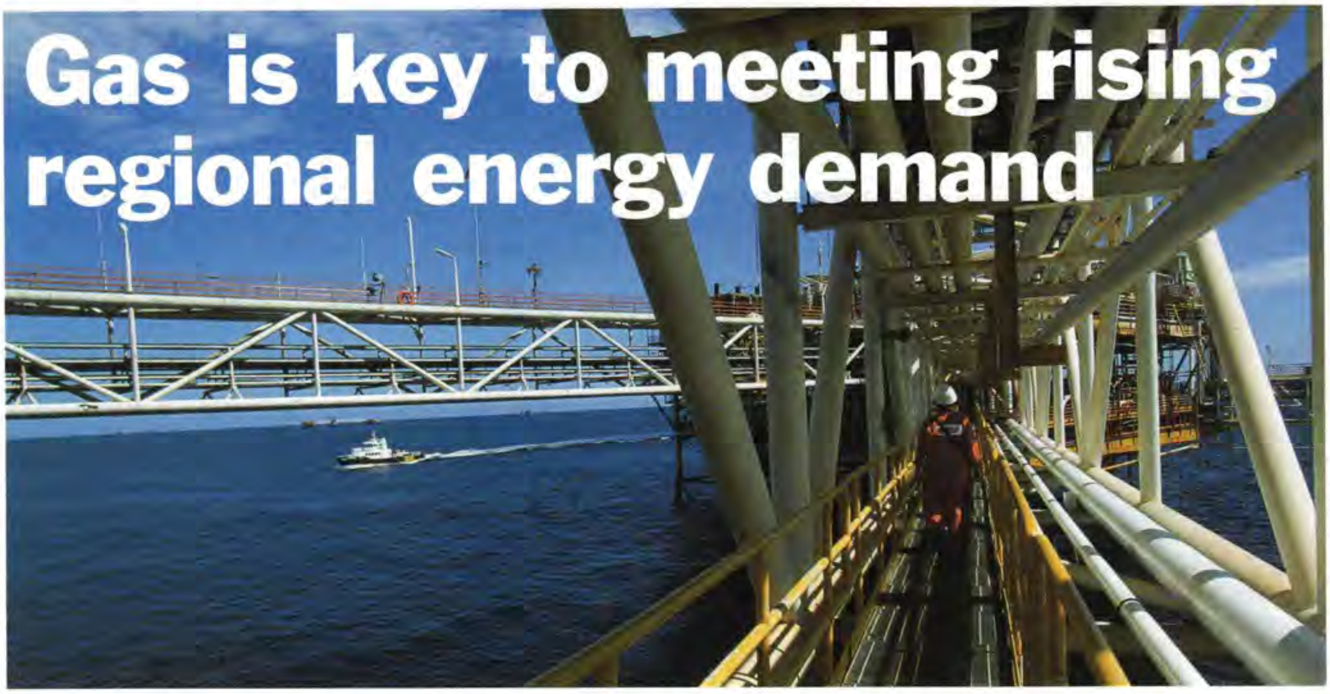

Photo: Shell International

Workers on Ampa 6, an offshore production platform in Brunei (see also p15)

The Asia-Pacific region is becoming ever more dependent on gas but has continued to report new gas discoveries to expand reserves. However, oil represents considerable challenges, in terms of discovery and reserves, if the region's dependence on Middle East and Russian supplies is not to escalate dramatically. Recognising this, many of the Asia-Pacific countries are seeking to diversify energy supplies, with LNG now set to play a key role.

The Asia-Pacific region contains some of the world's most dynamic economies. With a projected economic growth rate for the region of 6%/y to 2010, double the world's average growth rate, demand for energy is rising fast, in particular from China. The region consumes some 29% of the world's oil, a figure some analysts predict could rise to 40% by 2025. However regional production is only 10.25% of world output and reserves just 4.16% of the world total (see Table 1)

Faced with rising oil prices and concerns regarding security of supply, Energy Ministers from Japan, China, South Korea and the 10-member (Brunei, Cambodia, Indonesia, Laos, Malaysia, Myanmar, the Philippines, Singapore, Thailand and Vietnam) Association of Southeast Asian Nations (ASEAN) earlier this year began making emergency stockpiling plans that included the creation of strategic oil reserves and finding alternative sources for their energy imports. The Ministers also called for better sharing of oil data, more oil trade within Asia, dialogues and partnerships with producers outside the region, and investment in alternative energy sources such as natural gas. In addition, the Ministers stated a wish to improve the dissemination of coal technology as coal is an abundant and economical energy resource in this region, an area that is fast becoming the world's largest consumer of energy.

ASEAN Energy Ministers were also expected to adopt the ASEAN Plan of Action for Energy Cooperation for the period to 2009 – a plan for promoting sustainable energy development, integrated regional energy infrastructures and promoting energy security. It also contains policies for market reforms and liberalisation, as well as environment protection. Among the planned projects is the implementation of an ASEAN power grid, developing 11 bilateral power interconnectors. Five of these interconnectors are due to be commissioned between 2001 and 2010. In addition, there are increasing signs of cooperation between the region's state-owned energy companies – in particular Petronas of Malaysia, Pertamina of Indonesia, Thailand's PTT and Vietnam's PetroVietnam.

The funding required to develop an ASEAN power grid is considerable – some $100bn. Meanwhile, some $7bn is required to develop the trans-ASEAN gas pipeline network. There are already gas links between Singapore and Indonesia, Thailand and Myanmar, and Malaysia and Thailand. Other projects are planned to extend the existing gas grid, and new pipelines are planned between Indonesia, Brunei and the Philippines.

Gas is becoming an increasingly important energy source in the Asia-Pacific, with annual average demand for the region expected to increase by some 3.5% to reach 151tn cf by 2025. Regional gas consumption amounts to 13.33% of the world total with regional production accounting for 11.86% of the world total. Reserves of gas, at 7.66% of the world total, are rather more comfortable than for oil, but more reserves are needed if this traditionally gas exporting region is not to move to becoming a net gas importer. Over the next five years or so, major investment is anticipated in the Asia-Pacific's gas reserves, including the development of pipeline infrastructure (as outlined above) and additional LNG plants.

BANGLADESH

Natural gas accounts for almost 70% of Bangladesh's commercial energy and provides the basis for about 90% of its electricity generation. According to the Energy Information Administration (EIA), only two-thirds of Bangladesh's total electric generating capacity is considered to be 'available'. Problems include high system losses of up to 40%, delays in the completion of new plants, low plant efficiencies and shortages of funds for maintenance. Indeed, the World Bank has estimated that Bangladesh loses around $1bn/y in economic output due to power outages and unreliable energy supplies.

With only around 20% of the population having access to electricity and power demand growing rapidly, Bangladesh's Power System Master Plan (PSMP) forecasts a required doubling of electricity generating capacity by 2010. Furthermore, the country may need to replace up to 40% of its current generating capacity due to aging infrastructure.

As already indicated, gas is Bangladesh's only significant source of commercial energy. Although the country has been producing gas for more than three decades, all its major fields are underdeveloped and have not been properly delineated. Substantial natural gas reserves also remain underdeveloped, with further discovery confidently predicted.

However, in July the Asian Development Bank approved a $480,000 technical assistance (TA) grant that will help to prepare a natural gas sector development project to promote Bangladesh's economic growth. The TA will analyse opportunities for the sector's growth and review sector development plans prepared by the government and other development partners. It will also review existing policies and prepare reform measures to promote development and investment in the sector.

Earlier in the year Unocal revealed plans to go ahead with its $292mn plan to develop the large Bibiyana gas field in block 12 in northeast Bangladesh, four years after the initial proposal was rejected by the Bangladeshi government amidst debates over whether Bangladeshi gas should be exported. The export issue remains unresolved, with some politicians fearing such a move would pose a major political risk, while others declare that exports would hurt the national interest as Bangladesh must first be sure that it has a 50-year reserve.

Bibiyana gas will be used to meet the domestic shortfall as production from the country's five main fields continues to decline while demand continues to rise. Bangladesh is forecast to need between 1,400–1,500mn cf/d of gas from 2006 as it strives to achieve economic growth of up to 7%. At present the country produces some 1,262mn cf/d of gas, against daily demand of nearly 1,300mn cf/d. Bibiyana gas reserves are put at up to 6tn cf. The Energy Ministry puts Bangladesh's proven and probable reserves at 28.45tn cf of gas, of which 20.5tn cf are recoverable.

Even if exports of gas from Bangladesh to India fail to materialise, the country may eventually become a transit corridor for supplies from Myanmar to India, comments the EIA. India's state-owned companies GAIL and ONGC own equity stakes in Myanmar's offshore A-1 field. A pipeline across Bangladesh might also help India link natural gas reserves in its northeastern state of Tripura, east of Bangladesh, to major demand centres such as West Bengal. In June 2004 the Bangladeshi authorities stated that the government would be willing to consider transit pipelines crossing its territory, subject to conditions.

In other news, Bangladesh is reported to have agreed in principle to guarantee a 20-year gas supply for a power plant, fertiliser factory and steel unit to be built by India's Tata group in what is claimed would be the single largest foreign investment in Bangladesh to date.

BRUNEI

Photo: Shell International

According to Scottish Development International, although Brunei has a high GDP, with a projected growth in 2004 of around 3.3%, the economy is hindered by deep-set problems. Despite wide ranging reforms being announced in recent years, progress to date has been limited. The main problem is Brunei's heavy dependence on oil and gas, which make up 85% of the country's exports and account for a similar amount of government revenues – making the economy very susceptible to fluctuations in oil prices.

Brunei already attracts significant levels of foreign investment and is seeking a further $4.5bn by 2008 in order help efforts to diversify its economic base. Sectors specifically targeted for growth include petrochemicals, refining and shipping.

Brunei's oil sector, which produced 214,000 b/d in 2003, is dominated by Brunei Shell Petroleum (BSP). This company produces from seven offshore fields, including Champion which contains about 40% of the country's total oil reserves and produces some 50,000 b/d, and two onshore fields (Rasau and Seria-Tali). Another field, Egret, is due onstream in 2006 and is forecast to produce some 30mn barrels of oil over the next 15–20 years.

A pressing concern is the need to settle a territorial dispute with neighbouring Malaysia over deepwater acreage that includes blocks J and K off the coast of Borneo. As a result, the development of Murphy's 700mn-barrel Kikeh oil field which appears to extend into block J could be delayed.

Brunei is the fourth-largest LNG producer in the world and the third-largest natural gas producer in the Asia-Pacific region. Faced with increasing competition from regional and Middle East suppliers, in May Brunei LNG was reported to be planning to invest almost $300mn over five years to upgrade its LNG facilities. The company currently operates five LNG trains, each with around 1.3–1.4mn t/y capacity, and is looking to build an additional train of 4mn t/y capacity by 2008. Brunei LNG is 50%-owned by the government, 25% by Shell and 25% by Japan's Mitsubishi. Japan accounts for some 90% of Brunei LNG's production, while South Korea takes the remaining 10%.

In other news, Brunei Shell Petroleum (BSP) has made a successful discovery of new oil in the Seria North Flank, a previously undrilled part of the field that has been in production for 75 years. The well – which was drilled 3 km offshore in 8 metres of water – found approximately 400 metres of net gas and oil bearing sands of 'better reservoir quality than expected'. According to Mark Carne, Managing Director of BSP: 'We regard this as a very important discovery because there are up to 20 similar structures in this area. If this success is replicated we estimate total recoverable oil of up to 100mn barrels from the whole of the Seria North Flank.' BSP is now proceeding with plans to fast-track further exploration, appraisal and development of Seria's North Flank.

CHINA

(See also *Petroleum Review*, April 2004.)

China, the second largest oil consuming nation in the world, has seen a widening gap between demand for and the domestic supply of oil this year as the country's economy has experienced unprecendented levels of growth – 9.1% in 2003, 9.8% in 1Q2004. Oil demand is expected to grow to 6.8mn b/d in 2005, up 8.1% from the current estimate for 2004 of 6.29mn b/d, according to the International Energy Agency (IEA), while indigenous production is rising by just 1% per annum. Meanwhile, the EIA predicts oil demand will reach 12.8mn b/d by 2025, with net imports of 9.4mn b/d.

In order to help supply China's growing demand for oil imports, the country has been busy securing E&P interests overseas – including oil concessions in Kazakhstan, Venezuela, Sudan, Iraq, Iran and Peru. An important development was the acquisition by CNPC of a 60% stake in Kazakh oil company Aktobemunaigaz. According to the EIA, the Chinese and Kazakh governments signed an agreement in May 2004 for the construction of a $700mn pipeline to export Kazakh crude into western China. While the agreement originally cited a completion date of 2005, this appears unlikely as negotiations on a binding contract and pricing continue.

The Russian Far East is seen as an important potential source of oil for China and the two countries' governments have held regular discussions on the feasibility of pipelines to make such exports possible. One proposed plan, reports EIA, is a pipeline to carry 1mn b/d of oil from Angarsk in Russia to join the existing Chinese pipeline network at Daquing. An alternative plan proposed by Russian pipeline operator Transneft would take Russian crude from West and East Siberia via a 1mn b/d pipeline to an export terminal at Nakhodka on the Pacific coast.

Among new oil projects to come onstream this past year, Kerr-McGee (40%, operator) produced first oil from its development of the CFD 11-1 and CFD 11-2 fields on block 04/36 in Bohai Bay. A total of 10 wells were online by the end of July, with production ranging between 15,000–20,000 b/d of oil. Additional wells will be brought onstream over the next two years, with peak production in the range of 40,000–45,000 b/d expected by mid-2005. Partners in the development are CNOOC (51%) and Sino American Energy, a subsidiary of Ultra Petroleum (9%).

Development planning is ongoing for other discoveries on the 04/36 block, including the CFD 11-3, CFD 11-5 and CFD 11-6 fields, each operated by Kerr-McGee with an 82% predevelopment foreign contractor's interest. Development planning also is under way

Photo: ConocoPhillips

for two discoveries on the adjacent 05/36 block, the CFD 12-1 and CFD 12-1S fields, which are operated by Kerr-McGee with a 50% predevelopment foreign contractor's interest. Each of these discoveries is a candidate to be tied back to the Kerr-McGee *Global Producer VIII* facility.

Meanwhile, China National Offshore Oil Corporation (CNOOC) brought onstream its Qikou 18-2 oil field in the western part of Bohai Bay, producing more than 2,800 b/d of oil from five wells.

In other exploration news, CNOOC and Taiwan's Chinese Petroleum Corporation (CPC) unveiled plans to drill the second wildcat well in their joint venture acreage in the southeast Pearl River Delta Basin of the South China Sea some time in 2005, after the results of the first well were unsuccessful. CPC and CNOOC had planned to spud three wildcats in the block between January

Country	Reserves (bn barrels)	Change 02/03	R/P ratio (years)	Oil prodn (,000 b/d)	Growth 02/03 %	Oil consumpt (,000 b/d)	Growth 02/03 %	Gas reserves (tn cm)	Change 02/03
Australia	4.40	0.7 incr	19.3	624	-15.6	845	0.3	2.55	n/c
Bangladesh						87	5.0	0.34	n/c
Brunei	1.10	n/c	14.1	214	2.1			0.35	n/c
China	23.70	n/c	19.1	3,396	1.5	5,982	11.5	1.82	0.07
India	5.60	n/c	19.3	793	–0.1	2,426	1.9	0.85	0.10
Indonesia	4.40	0.3 decr	10.3	1,179	–8.6	1,131	1.5	2.56	n/c
Japan						5,451	2.1	*	
Malaysia	4.00	0.2 decr	12.5	875	5.5	519	6.4	2.41	–0.07
Myanmar								0.36	n/c
New Zealand						149	5.0	*	
Papua New Gu	0.40	n/c	22.5	n/a				0.43	n/c
Pakistan						342	–5.1	0.75	–0.01
Philippines						332	–0.1	*	
Singapore						672	–3.9	*	
South Korea						2,303	1.0	*	
Taiwan						880	4.2	*	
Thailand	0.70	n/c	8.7	217	15.7	812	6.2	0.44	n/c
Vietnam	2.50	n/c	18.4	372	4			0.23	n/c
Other Asia-Pacific	0.90	n/c	15.4	203	1.3	399	–2.5	0.39	n/c
Total Asia-Pacific	47.70	0.2 incr	16.6	7,872	–1	22,601	4.0	13.47	0.11
Total World	1,147.70	1.4 incr	41.0	76,777	3.8	78,112	2.1	175.78	0.63
Asia-Pacific as %	4.16	–	–	10.25	–	28.93	–	7.66	–

Table 1: Asia-Pacific production, consumption and refinery capacity, 2002–2003
Source: BP Statistical Review, June 2004, *interpreted by* Petroleum Review; *Totals for countries not individually itemised; *included in 'Other Asia-Pacific'

2003 and December 2006. However, the start of the entire joint exploration programme was delayed by the SARS outbreak in China and the rest of Asia in the first half of last year. CPC and CNOOC also have an agreement to conduct joint research and survey at a block near the Penghu island in the Taiwan Strait of the South China Sea.

CNOOC is also reported to have confirmed the commercial potential of the Weizhou (WZ) 11-1 discovery well in the western waters of the South China Sea. It is estimated that over 3, 000 b/d of oil and 340, 000 cf/d of gas can be produced. Meanwhile, an additional 52.63bn cm of proven gas reserves have been announced for the Tainan gas field, boosting total proven field reserves to 95.16bn cm. Total proven gas reserves for China's Qaidam Basin are now put at 303.9bn cm.

Gas will play a key role in the future growth of China's economy, helping to plug the energy deficit. According to the EIA, gas production is expected to rise by 4.5%/y to 2025, reaching some 1.6tn cf/y by 2010 and 3.1tn cf/y by 2025. However, forecast demand of some 5tn cf/y by 2025 will outstrip domestic supply and imported gas, particularly in the form of LNG, will become increasingly important.

A number of major projects are planned, including the country's first LNG import terminal in Guangdong Province that will be supplied with 3mn t/y of LNG from the North West Shelf project offshore Australia. Construction of a second LNG terminal at Fujian is to begin in 2007. It will be supplied with up to 2.6mn t/y of LNG from Indonesia's Tangguh LNG project (see Indonesia – p19). Orginally due onstream in 2007, reports as *Petroleum Review* went to press indicated that problems ranging from government approval of Tangguh's marketing plans to the completion of construction at the site, may delay commissioning until 2008. A third terminal is planned in Zheijiang Province, due to be commissioned in 2009 with a capacity of some 3mn t/y. A tentative agreement was signed by CNOOC in April for a fourth terminal in Tianjin Province.

Another potential gas supplier is Iran. A memorandum of understanding was signed by Chinese oil trader Zhuhai Zhenrong and National Iranian Gas Exporting Company in March for the supply of 2.5mn t/y of gas from 2008, rising to 5mn t/y by 2013.

Earlier this year, Sinopec was reported to be stepping up efforts to expand its natural gas operations in eastern China's Shandong Province, aiming to make it the company's largest gas consuming centre. The company is understood to be planning to supply Shandong with some 6bn cm/y of gas by 2010 from four sources in the central, north and northwest of the country, and from imports of LNG. It is thought that the proposal may trigger competition between Sakhalin in Russia, Iran, Australia and Indonesia – all of which have expressed an interest in supplying Sinopec with gas at an initial rate of 3mn t/y, rising to 5mn t/y in the future.

At present, Sinopec supplies gas to Shandong from its Zhongyuan gas field in Henan Province. Sinopec's largest gas field, Zhongyuan produced 1.7bn cm of gas last year. The company plans to raise production to 2bn cm within the next 18 months. Before LNG imports start arriving in 2007 or 2008, additional gas will be piped to Shandong from PetroChina's West-East pipeline, in which Sinopec has a 5% stake, and from the Ordos Basin in the north. Sinopec is also developing the Daniudi gas field in Inner Mongolia, which has proven reserves of 250bn cm, and is preparing to build a pipeline from it to Shandong. The field could supply 1mn cm/y of gas by 2006.

Meanwhile, tensions between China and Japan over the gas reserves in the East China Sea have continued this year. At the heart of the dispute is the Chunxiao gas field being developed by CNOOC. Japan has argued that the field may extend between the median line between the two countries (see Japan – p20).

In other company news, CNOOC is understood to be planning to increase its domestic oil and natural gas output by more than 7%, from 37mn cmoe in 2003 to 40mn cmoe by 2008. Commercial targets include turnover exceeding $20bn, daily oil and gas output of 1mn boe with overseas production accounting for 30% of the total, and an integrated business structure covering upstream, midstream and downstream.

Looking downstream, PetroChina began filling the second development phase of its 4,000-km, 12bn cm/y cross-country pipeline with natural gas in September. The pipeline, starting from the Lunnan field in the Tarim Basin of northwest China's Xinjiang Province,

R/P ratio (years)	Gas prodn (bn cm)	Growth 02/03 %	Gas consumpt (bn cm)	Growth 02/03 %	Refinery cap (,000 b/d)	Growth 02/03 %	Refinery t'pt (,000 b/d)	Growth 02/03%
76.9	33.20	1.70	26.30	4.50	873	–7.6	815	–4.70
27.8	12.20	6.90	12.20	6.90				
28.3	12.40	7.80						
53.4	34.10	6.80	32.80	10.60	5,487	0.1	4,871	10.80
28.4	30.10	4.80	30.10	4.80	2,333	1.9		
35.2	72.60	3.20	35.60	3.20	1,056	n/c		
			76.50	6.50	4,683	–0.8	4,118	3.30
45	53.40	10.10	28.40	6.10				
	6.90	7.20						
	5.40	–2.20	4.60	–16.20				
100+								
35.5	21.10	2.50	21.10	2.50				
			2.70	52.40				
			5.30	8.60	1,255	n/c		
			26.90	4.70	2,316	n/c		
			8.70	2.10	1,159	n/c		
22.3	19.60	3.70	26.60	9.10	860	1.4		
76.7								
32.9	9.60	22.80	6.10	17.60	1,292	–4.4	9,280	5.10
43.4	310.50	5.50	345.50	5.70	21,314	–0.5	19,084	
67.1	2,618.50	3.40	2,591.00	2.00	83,658	0.4	71,091	2.40
–	11.86	–	13.33	–	25.48	–	26.84	–

spans eight provinces and autonomous regions to reach eastern China's commercial hub of Shanghai. The first phase of the pipeline, which links Jingbian to Shanghai, began commercial operation in January 2004. The gas handling capacity of the pipeline can be expanded to 18bn cm/yr by adding a compressor along the route. The Tarim Basin gas fields are the main source of gas for the pipeline. Proven gas reserves are put at 658bn cm. By the end of 2003 a total of 14 gas fields had been found in the Basin. Among the first to supply gas are the Yaha, Kela 2, Sangnan, Jilake and Ji'nan 4 field. The Kela 2 field alone is reported to have proven reserves of 284bn cm.

Another proposed gas pipeline project would link the Russian natural gas grid in Siberia to China and South Korea via a pipeline from the Kovykta gas field (see South Korea – p23).

More recently, Fujian Petrochemical (a company owned 50% by Sinopec and 50% by the Fujian government), ExxonMobil and Saudi Aramco unveiled plans to jointly fund the front end loading (FEL) design activity for a more than $3.5bn project involving expansion of the existing refinery at Quangang, Quanzhou City, Fujian Province, and the addition of a chemical complex. The project will expand capacity at the existing refinery from 80,000 b/d to 240,000 b/d, with significant product upgrading capability. The upgraded facility will be designed to refine and process sour Arabian crude. In addition, the project involves construction of a new 800,000 t/y ethylene steam cracker, polyethylene and polypropylene units, and a new 700,000 t/y paraxylene unit. Currently, completion is expected in 1H2008.

Meanwhile, ExxonMobil, Sinopec and Saudi Aramco have also agreed to submit a joint feasibility study (JFS) for a fuels marketing joint venture in Fujian Province to the Chinese government. The joint venture plans to manage and operate more than 600 service stations and a network of terminals.

EAST TIMOR/TIMOR SEA

In June East Timor and Indonesia signed a key accord to mark their common border. The accord covers more than 90% of the border and both sides were keen to map out the remainder over the following months. The demarcation is expected to improve security and help reduce rampant smuggling between East Timor and Indonesian-held West Timor, which share an island just north of Australia.

More recently, East Timor and Australia have resumed talks on maritime boundaries and dividing the Timor Sea's oil and gas reserves that have been valued at some $30bn (A$42.74bn). Under an interim deal, East Timor is to get 90% of government revenue from the joint petroleum development area – including the ConocoPhillips-operated Bayu Undan project and part of the Woodside Petroleum-operated Sunrise field. However, under a second deal, the international unitisation agreement, only 20% of the Sunrise field lies in the joint development zone, with the remaining 80% going to Australia. Negotiations were ongoing as *Petroleum Review* went to press.

In other news, Santos of Australia has reached an agreement with ConocoPhillips to jointly explore the NT/P61 licence area in the Timor Sea. The two companies are already working together on the Bayu-Undan liquids and LNG project. ConocoPhillips will hold a 60% stake in the new project and will act as operator. It will also fund the permit area work programme, including the drilling of the Caldita 1 well.

Photo: ConocoPhillips

INDIA

(See also *Petroleum Review*, May 2004; July 2004.)

India is actively pursuing projects abroad in order to secure more supplies as some of its larger oil fields enter decline and the robust economy (projected 2004 GDP of 6.4%) fuels rising demand for petroleum products. India's energy demand is currently rising by more than 3%/y, compared with a global average of less than 2%.

The Sudanese authorities are reported to have approved a proposal from India's Oil and Natural Gas Corporation (ONGC) for a petroleum product pipeline linking the Khartoum refinery to Port Sudan on the Red Sea. India currently imports some 70% of its domestic crude oil requirements.

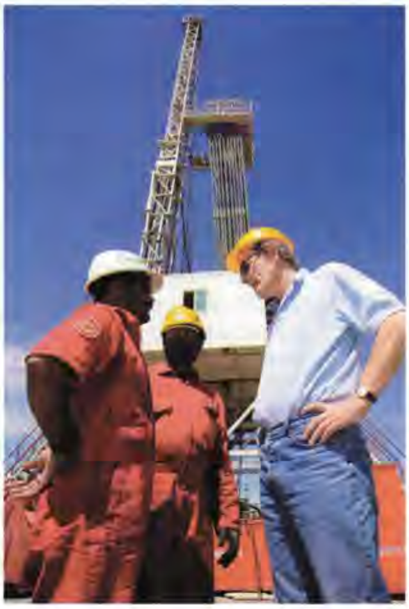

Photo: Cairn Energy

Meanwhile, the Indian government cut customs and excise duties on most petroleum products in August in a bid to curb inflation, which had soared during the month due to rising global oil prices and late monsoon rains. Gasoline and diesel customs duties were lowered to 15% from 20%, while duties on kerosene and cooking gas were to be halved to 5%. In addition, excise duties on gasoline were to be cut to 23% from 26%, and those on diesel lowered to 8% from 11%.

The government was also reported to be considering a merger of state-run oil companies in order to create stronger, more efficient businesses. The idea is thought to be among various options aimed at achieving energy security for the country. However, according to Petroleum Minister Mani Shankar Aiyar, no formal proposals have been put forward to date.

Gas is playing an increasingly important role in India's energy mix, with consumption projected to rise from 65mn cm/d to 300mn cm/d by 2025, while the share of gas in its domestic energy sector is expected to increase from 8% to 20%.

A number of domestic gas projects are to be developed, including Reliance Industries (90%) D6 field in the Krishna Godavari Basin off the Andhra Pradesh coast, with first gas targeted in August 2006 at an initial rate of 500mn cf/d. Almost the entire output of the first phase of field development will be taken by National Thermal Power's Kawas and Gandhar power projects in Gujarat, for which the company plans to lay a pipeline from Kakinada to Uran. Field reserves are put at 14.5tn cf of gas.

Canadian Niko Resources holds the remaining 10% stake in the field.

Meanwhile, BG – together with partners Oil and Natural Gas Corporation (ONGC) and Reliance Industries – is to invest \$140mn in the Panna oil and gas field, offshore Mumbai, to target new reserves and expand current production. The development plan comprises construction and installation of two new wellhead platforms and associated infield pipelines to connect to the existing processing and compression platform. The drilling schedule, to begin in 2Q2005, includes six horizontal wells from one platform and five horizontal wells from the other. The expansion programme is expected to result in gross incremental recovery of 74bn cf of gas and 18mn barrels of oil. First production is expected in 3Q2005. Panna is estimated to have original gas in place of 1.8tn cf and 1bn barrels of oil. The field is part of the Panna/Mukta and Tapti concessions, in which BG India holds 30% interests. ONGC holds 40%, while the remaining shareholding is owned by Reliance. Current production from the Panna/Mukta and Tapti fields contribute about 7% of India's total oil and gas production.

In other E&P news, state-owned GAIL and Gujarat State Petroleum discovered oil in Cambay Basin block CB-ONN-2000/1 in Gujarat state. Recoverable reserves are estimated to be 10mn barrels, with an upside potential of 50mn barrels. In July Cairn Energy reported that the Mangala-5 and Mangala-6 appraisal wells in northern Rajasthan had confirmed the 'continuity and connectivity of excellent reservoirs across the Mangala field, which is positive for the determination of ultimate recovery'. Mangala-5 flowed 1,786 b/d and 2,153 b/d of oil from Zones 1 and 2, respectively. A 3D seismic survey over the Mangala and NA fields is due to complete in by the end of the year. First production from Mangala is expected in late 2007.

LNG is also to play a key role in meeting India's rising energy demand. In May ONGC proposed establishing an LNG terminal on the Mangalore coast. Some of the terminal's gas will be supplied to Mangalore Refineries and Tannirbhavi Power located in the state's coastal region. Meanwhile, the board of Petronet approved the doubling of capacity at the Dahej LNG receiving terminal in northwest India from 5mn t/y to 10mn t/y, although no date has yet been given for the likely start-up of the extra capacity at what is India's first LNG terminal. Petronet Chief Executive Suresh Mathur also confirmed that India will buy 5mn t/y of LNG from Iran under a 20-year contract scheduled to begin in 2010. Iran's Pars LNG project is aiming to produce 8mn t/y from 2009.

More recently, GAIL proposed taking over the moribund Ennore LNG project in Tamil Nadu. The immediate region is short of gas supplies and GAIL says that four power stations would support the project, which could source LNG supplies from a variety of producers in southeast Asia or Australia. GAIL also has plans to extend the gas pipeline network in order to supply gas to Bangalore and Tuticorin.

INDONESIA

(See also *Petroleum Review*, January 2004; p36.)

Indonesia is the only Asia-Pacific nation to be a member of Opec, producing some 1.18mn b/d of oil from proven reserves of 4.4bn barrels (according to the latest *BP Statistical Review*). However, output is declining as fields mature – particularly those onshore. Remaining potential is almost exclusively offshore, although most of the shallow water area has been extensively explored.

It has been reported that Indonesia's Mines and Energy Minister is considering a reduction in the share that the government takes in oil and gas revenue in a bid to encourage E&P companies to develop their marginal fields and increase production via enhanced oil recovery (EOR) projects.

According to Scottish Development International's *Spends and Trends 2004* there are some 60 marginal oil fields yet to be developed in the region, with the potential to add between 200,000 and 300,000 b/d of oil. Exploration drilling is expected to dominate annual Indonesian activity through to 2008, as new opportunities are sought in more remote areas. According to the *Spends and Trends 2004* report, recent activity has been relatively strong, with a total of 269 exploration and appraisal wells drilled over the past five years. However, the period to 2008 is anticipated to see a continual decline in numbers of wells drilled annually, from 50 in 2003 to 33 in 2008, with a total of 195 forecast through to 2008.

The report also states that total Indonesian production is anticipated to increase year-on-year from 2004 onwards, driven in the main by new gas developments. Production is expected to reach 1.99mn boe/d by 2008, with gas accounting for some 1.3mn boe/d.

Development projects include the Unocal-operated West Seno field – Indonesia's first deepwater project. Peak production of 60,000 b/d of oil and 150mn cf/d of gas is expected to be reached by the end of 2005 after the second phase of development has completed. In August Unocal reported that bid results for the recently opened Phase 2 development of the West Seno field, including offshore installation and tension leg platform fabrication, were 'unacceptably high'. As a result, cost reduction options are now being considered, and the construction period is expected to extend beyond 2005. West Seno currently has 20 completed wells, with gross production averaging 24,000 boe/d in June. By year-end 2004, 26 to 28 wells are expected to be online with an expected exit rate (gross) of 25,000–35,000 boe/d.

Meanwhile, Unocal and partner Eni have selected a development concept for the first phase of the Gendalo field development project in the Ganal production sharing contract (PSC) offshore Indonesia. This first phase will be designed to produce 250–300mn cf/d of gas, beginning in 2007. The project will target existing contract requirements for the Bontang gas market and new sales.

Due onstream more immediately is ConocoPhillips' Belanak field, with reserves put at 530bn cf of gas and some 100mn barrels of oil, condensate and LPG. First oil is anticipated in December 2004 at an initial production of 10,000 b/d, rising to around 40,000 b/d in 2005. The field is to be developed via an FPSO capable of handling some 100,000 b/d of oil and with a storage capacity of 1mn barrels. The FPSO is also reported to be the first to be equipped

with LPG production facilities.

TGS-Nopec has commenced the acquisition of a new non-exclusive 2D survey in waters of Indonesia's Makassar Strait. The 5,200 km survey will complement and infill data acquired by the company's earlier surveys. The new dataset will enable petroleum explorers to better define the geological history of the area, which has already attracted significant interest from the global exploration community. The area covered by the survey is likely to be offered in a bid round by the Indonesian Government during 2H2005.

In other news, ConocoPhillips has signed a gas sales agreement with Perusahaan Gas Negara (PGN), the Indonesian state-owned gas transportation company, to supply a base load of 2.3tn cf of gas for delivery over 17 years to the industrial market located in West Java and Jakarta. The contract will commence in 1Q2007 at a rate of 170mn cf/d. The gas will come from the ConocoPhillips-operated Corridor Block PSC located in South Sumatra. Gas deliveries will plateau at 400mn cf/d in 2012 until the contract termination in 2023.

This natural gas sale to PGN will underpin the further expansion of gas production and gas-processing facilities at the Suban gas field in the Corridor PSC operated by ConocoPhillips. This development, known as Suban Phase 2, will be connected to the Corridor PSC's existing gas processing facilities at Grissik in south Sumatra. PGN will construct a new pipeline from Grissik, through South Sumatra to Cilegon in West Java. A further pipeline also will be built to connect Grissik to Muara Tawar east of Jakarta. Construction of the 606-km Grissik-to-Muara Tawar pipeline is scheduled to take 30 months. The establishment of a dual pipeline system to customers in Jakarta and West Java will promote the expanding domestic gas market in Java. ConocoPhillips is the operator of the Corridor Block PSC with a 54% interest. Other partners are Talisman (36%) and Pertamina (10%).

Indonesia is a major source of LNG supply to neighbouring Japan, South Korea and Taiwan, and is looking to export to China and India from Bongtang and from Tangguh in Irian Jaya. The Tangguh LNG project, now due onstream in 2008 (see p17), will produce some 7mn t/y from two initial processing trains. Feedstock gas will come from BP's nearby Wiriagar and Muturi fields that have reserves in the region of 14.4tn cf.

Most recently, BP and its partners in Tangguh have signed a sales and purchase agreement with K Power of South Korea for the supply of up to 800,000 t/y of LNG for 20 years. The LNG will be used to power K Power's new 1,074-MW power station being built at Gwangyang in southwestern South Korea, due to commence operations in 2006. K Power, formerly known as SK Power, is a joint venture between SK Corporation (65%) and BP (35%). The signing follows an earlier agreement, signed in July, for the supply of 550,000 t/y of LNG to Posco, Korea's largest steelmaker, and completes the process outlined in the heads of agreement signed between SK Corporation and the Tangguh partners in July 2003. The LNG supplied under both agreements will be delivered to Posco's new Gwangyang LNG import and regasification terminal, which is currently under construction.

In addition to the K Power contract, the Tangguh project has sales and purchase agreements in place for the supply of 0.5mn t/y of LNG to Posco and 2.6mn t/y of LNG to China's Fujian LNG import terminal. The project is also in the process of finalising a further agreement to supply up to 3.7mn t/y of LNG to Sempra Energy's proposed LNG import terminal at Costa Azul in Mexico.

Meanwhile, Petronas of Malaysia has signed a memorandum of understanding (MoU) with Indonesia's PT Perusahaan Listrik Negara (or PT PLN (Persero)) towards the development of a LNG regasification terminal in West Java. The terms of the MoU include plans for the two parties to undertake a joint study for the proposed development of the project, to be known as West Java regasification terminal. The facility will initially have a capacity of 400mn cf/d, eventually building to 800mn cf/d. Expected to be operational in 2007, the terminal will complement Indonesia's existing gas supply sources to meet the growing gas demand in that country. Petronas has also ventured into Indonesia's downstream business, mainly in the marketing and distribution of its petroleum products.

JAPAN

Japan is almost totally dependent on imports to meet its energy needs, importing from its Asia-Pacific neighbours as well as from Kazakhstan, Russian and the Middle East.

Japanese companies have been active overseas since 1967, when the government established the Japan National Oil Company (JNOC) to promote overseas oil exploration. While JNOC is to be dissolved by July 2005, overseas projects will continue to play a key role for Japan. One important project is Azadegan in Iran, a binding contract for which was signed by Japan and the National Iranian Oil Company in February 2004. Initial production is expected by 2007, with peak production of 260,000 b/d by 2012.

Another possible source for Japanese oil imports is the Russian Far East and Japan has been promoting a proposed pipeline from oil fields in Siberia to an export terminal on the Pacific coast at Nakhodka. Meanwhile, gas deliveries from the Russian Far East's Shell-led Sakhalin II project are to begin arriving in 2007. Gas could also come from the ExxonMobil-led Sakhalin I project via a pipeline to Japan's main island of Honshu.

Keen to secure domestic supplies, in June Japan's Industry Minister Shoichi Nakagawa stated that the country would start exploring for natural gas resources in its exclusive economic zone (EEZ) in the East China Sea, in a move that some industry pundits said appeared to be a plan to counter China's oil exploration near the area (see China – p16). Earlier in the month, the Japanese government was reported to have lodged a complaint with Beijing that the Chinese Chunxiao gas project could violate the boundaries of Japan's EEZ, after learning the Chinese had begun constructing a drilling facility nearby. Japan argues that it has a right to claim its share if resources are found straddling the intermediate line. Up to 200bn cm of natural gas reserves are estimated to exist in several fields in the area.

In turn, China expressed 'grave concerns' about Japan's announcement and Chinese officials sent ships in to conduct research on the Japanese side of the area divided by the intermediate line.

The United Nations (UN) Convention on the Law of the Sea allows coastal countries to regulate seabed resources in their economic zones, which extend 370 km from their shores. However, Beijing and Tokyo, both of which signed the convention in 1996, are unable to agree over the zones as they partly overlap. China maintains that the border is where the continental shelf ends, as is the international custom. But Japan contends that both zones meet halfway between the shores. The UN says it will decide on global offshore territorial claims by May 2009.

In other news, Nippon Oil Corporation is reported to be planning to build a secondary LNG storage terminal at its Hachinohe oil storage terminal in northern Japan. The proposed terminal is scheduled to start operations in March 2007.

MALAYSIA

(See also next month's issue – *Petroleum Review*, December 2004.)

Malaysia is a mature oil and gas producer and a significant energy exporter. However, a lack of major discoveries in recent years means that reserves are declining and there are fears that the country could become a net oil importer by the end of the decade. That said, according to Scottish Development International, total Malaysian production is expected to rise steadily from 1.8mn boe/d in 2003 to 2mn boe/d by 2008, principally driven by gas projects. Annual gas production is expected to increase from 974,000 boe/d in 2003 to 1.2mn boe/d in 2008.

Because of the lack of major domestic oil discoveries, state-owned Petronas has increasingly looked overseas to grow its E&P portfolio. It currently has operations in Iran, Algeria, Tunisia, Syria, Angola and elsewhere, with approximately one-third of its revenues coming from foreign operations. The company is also seeking to expand its overseas presence in the LNG market, recently signing, through its subsidiary Asean LNG Trading, a gas sales agreement with British Gas Trading, a subsidiary of Centrica, to supply up to 3bn cm/y of natural gas for 15 years, beginning 2007. The deal marks a major breakthrough for Petronas in its quest to enter the UK natural gas market and at the same time will enhance its overall position in the global LNG business. The company currently has long-term contracts mainly with traditional customers in the North Asian market, meeting about half of Taiwan's LNG needs, 25% of Japan's needs and 20% of Korea's requirements.

Under the agreement, Petronas will supply the gas to Centrica via the LNG receiving terminal being developed by Dragon LNG at Milford Haven, Wales. Petronas will deliver LNG from its portfolio of current and future supply sources to Milford Haven via tankers owned by its subsidiary Malaysia International Shipping Corporation. At the terminal, the LNG will be re-gasified before it is supplied to Centrica, which in turn will supply the gas to its British Gas customers.

Petronas has 30% equity in Dragon LNG, while BG Group and Petroplus have 50% and 20% stakes respectively. The terminal will be able to process up to 6bn cm/y of gas and is scheduled to start operation by 2007. The 3bn cm of natural gas to be supplied to Centrica will make up the entire 50% of the terminal's planned throughput capacity that Petronas intends to use under a separate agreement reached between the partners. The other half of the capacity will be used by BG Group.

Petronas claims to currently be the world's largest LNG capacity owner. Apart from its Malaysian production facility in Bintulu, Sarawak, and the Milford Haven project, the company has a 35.5% stake in the Egyptian LNG

Photo: ConocoPhillips

(ELNG) project. The ELNG project will receive its natural gas supply from an Egyptian gas concession equally owned by Petronas and BG Group. Earlier this year, Petronas also signed a shareholders agreement for a 20% stake in Pars LNG, a joint venture to develop an LNG production facility in Iran.

Meanwhile, the Malaysian government is pressing ahead with the fast-track development of its substantial gas fields and approval has come quickly for many industrial, petrochemical and power generation projects utilising gas.

Shell's Jintan gas field came onstream in September. It is the second gas field brought into production under the SK8 production sharing contract offshore Sarawak, following Serai which came onstream in June 2004. Jintan has been developed as an unmanned satellite to the nearby M1 gas production facilities, supplying feed gas to Petroliam Nasional's third LNG plant – MLNG Tiga – in Bintulu. Together with Serai production, a total of 970mn cf/d of gas will now be supplied by the SK8 production contract to MLNG Tiga. Partners in the production sharing contract are Shell (operator, 37.5%), Nippon Oil Explorations (37.5%) and Petronas Carigali (25%).

Earlier in the year Talisman Energy signed a production sharing contract for block PM-314 offshore Malaysia. The block is located adjacent to the PM-305 block on which Talisman made the South Angsi oil discovery in 2003. South Angsi is estimated to contain 18mn barrels of proved and 7mn barrels of probable oil reserves; first production is expected in mid-2005.

In August Petronas claimed to have drilled Malaysia's longest development well to date on the main Angsi field. The Angsi A-28ST-1 well reached its total depth of 6,339 metres on 11 August, just 44 days after it was spudded. The 80° extended reach drilling (ERD) well penetrated an oil reservoir, potentially containing 4.5mn barrels of oil, about 5.8 km from the Angsi platform. The well will be completed as oil producing well. The Angsi field is operated by Petronas, with a 50% stake, partnered by ExxonMobil. Developed in three phases, the field is now producing about 100,000 b/d of oil and 200mn cf/d of gas.

The Cendor field in offshore block PM 304 is due onstream in late 2006/early 2007. Earlier this year, Petrofac acquired the Amerada Hess subsidiary that operates and owns a 40% interest in Cendor. The remaining partners are Petronas Carigali (30%), Kuwait Foreign Petroleum Exploration (25%) and PetroVietnam (4.5%).

Also due onstream in 2006 is ExxonMobil Exploration and Production Malaysia's (EMEPMI) Guntong E field. EMEPMI is operator of the gas production-sharing contract (GPSC) with joint-venture partner Petronas Carigali – both holding 50% stakes. The Guntong E facility will consist of an eight-leg jacket and modules for gas receiving, separation, dehydration and compression. Three large turbine-driven compressor trains will handle 540mn cf/d of gas and 30,000 b/d of condensate. Production will flow to shore using existing pipelines. The platform is to be installed offshore by 3Q2005. Guntong E will form the hub for offshore gas production from several fields and is expected to process 4tn cf of gas for sale in Peninsular Malaysia.

Recent news includes the discovery by Shell, Petronas Carigali and partner ConocoPhillips of oil in deepwater block G, with the Malikai-1 well. The discovery was made approximately 110 km from the Gumusut field in block J. Meanwhile, Murphy Oil announced a discovery on its Kakap-1 exploration well in block K. The find follows the world-class Kikeh discovery in block K in 2003, which is due to come onstream in 4Q2007 (although this may be subject to delay due to the ongoing territorial dispute with neighbouring Malaysia over deepwater acreage that includes blocks J and K).

CS Mutiara Petroleum, a 50:50 joint venture between Shell and Petronas, is reported to have discovered gas in block PM301 offshore northeast Malaysia. Recoverable reserves are estimated at 200bn cf. Bunga Zetung-1 is the second successive discovery in block PM301, following the success of the Bunga Kamelia gas discovery in November 2003. The new discovery is located 20 km south-east of the Bunga Kamelia gas field. CS Mutiara Petroleum has near-term plans to pursue drilling of a number of nearby exploration prospects in the block as part of its exploration and appraisal campaign prior to embarking on development of these gas fields.

MALAYSIA-THAILAND JDA

The Malaysia-Thailand Joint Development Area (JDA) is an overlapping economic zone located in the Gulf of Thailand, which was established to resolve the overlapping claims between the two countries' over the area's hydrocarbon reserves. It is divided into three blocks – A18, B17 and C19 – and is administered by the Malaysian-Thailand Joint Authority (MTJA).

The first field to enter production will be the Cakerawala gas field, due onstream in 1H2005. Gas production is expected to be in the region of 390mn cf/d.

PTT and Petronas announced an agreement in November 1999 to develop a gas pipeline from the JDA to a processing plant in Songkla, Thailand, and a pipeline linking the Thai and Malaysian gas grids. Although the project initially proved controversial in Thailand, with opposition from local residents in Songkla and along the pipeline route, construction began and first deliveries of gas into Malaysia are expected in mid-2005.

More recently, Malaysia's Petronas (50%) and PTT of Thailand (50%) have signed a production sharing contract (PSC) for block B-17-01. Petronas and PTT are also partners in blocks B-17 and C-19 PSC in the MTJDA.

NORTH KOREA

Anglo-Irish oil company Aminex recently signed a 20-year deal under which it will provide technical assistance to North Korea and will undertake exploration and production in the country. Aminex regards North Korea as 'highly prospective'. Should the company strike oil, it will get royalties on any of its own production, as well as being entitled to earnings from wells drilled by other firms.

Aminex Chief Executive Brian Hall is reported to have stated that he hoped developing North Korea's oil industry might help to 'thaw international relations', which have become 'frosty' in recent months amid concerns about the country's nuclear programme. 'At present, relations between North Korea and the outside world are strained, but the important relationship with South Korea appears to be improving and commercial cooperation is on the increase,' he said. 'An expanding energy industry may possibly help to build bridges between North Korea and the outside world.'

In July first gas was produced from the Donghae (East Sea)-1 field in Ulsan, South Kyongsang Province, on the Korean Continental Shelf. Reserves are reportedly put at about 5mn tonnes when converted into LNG. Although this isn't enough to cover even one month of Korean demand – the country currently uses 80mn t/y of gas – the project will provide important local experience, a spokesperson from national company KNOC said.

PAKISTAN

OMV began full production from the Sawan gas field in southern Pakistan on 22 October 2003. Output of 9mn cm/d more than tripled the Austrian company's production in Pakistan from 5,000 to 18,000 boe/d, reportedly making it the largest international gas operator in the country. OMV will now be responsible for meeting 18% of Pakistan's gas demand. Some 60% of this demand will be met by production from Sawan, 30% from the Miano field and 10% from Kadanwari.

In mid-2004, the government of Pakistan restated its willingness to permit a gas pipeline linking Iran's reserves to Indian markets across Pakistani territory. In return, Pakistan would earn transit fees and would be able to purchase gas from the pipeline when and if its own demand was sufficient. However, India has been reluctant to move forward with the project while military and political tensions with Pakistan over Kashmir persist. Indian officials have been reported as saying that the plan may be considered if Pakistan could provide security guarantees for the project.

Another gas import possibility is an eventual link with the Dolphin project under which gas is to be supplied from Qatar's North Dome gas field to the United Arab Emirates and Oman via a subsea pipeline from Oman. Pakistan has signed a preliminary agreement to eventually purchase gas from Qatar.

More recently, the Pakistan government granted two petroleum exploration licences to Pakistan Petroleum covering block 2766-1 in the Khuzdar district of the Balochistan Province and 2568-13 (Hala) in the Hyderabad and Sanghar districts of Sindh Province.

PHILIPPINES

A heavy dependence on oil imports means the Philippine economy is very susceptible to fluctuations in the oil price. Meanwhile, the gas sector is dominated by the Malampaya gas-to-power project in the Palawan Basin that completed in 2001. Although further gas and condensate discoveries are thought likely in the Palawan Basin, new gas markets are required, states Scottish Development International.

In March, the Philippine authorities were understood to have given the green light to local utility GNPower to construct what is claimed will be the country's first LNG terminal, at Mariveles in Bataan Province. Work on the 1mn tonne storage capacity facility is to complete by 2007. Production from the LNG plant will primarily be used as feedstock for a new 1,200 MW power plant, also being constructed by GNPower. Any surplus gas could be used as feedstock at the 600 MW diesel-fired Limay plant, currently being offered for sale on the condition that the buyer purchasing the plant converts it to a gas-fired facility.

Meanwhile, Petronas has teamed up with Philippine National Oil Company (PNOC) to explore for oil and gas offshore Mindoro in southern Luzon.

SINGAPORE

Singapore imports all of its gas requirements – some 0.5bn cf/ d – from Indonesia and Malaysia. However, it has been beset by power supply problems, with the city of Singapore experiencing a number of blackouts in June. Early investigations suggested the cause for these power outtages was a disruption in the gas pipeline from Indonesia's West Natuna fields.

Despite being totally dependent on energy imports, Singapore's position and political stability make it an ideal candidate to develop as a regional hub in the ASEAN gas grid.

In recent news, 3i, a leading international private equity and venture capital company, has completed a $15mn growth capital investment in Singapore-based Pearl Energy for an undisclosed minority equity stake. Pearl has a portfolio of oil and gas interests across Indonesia, Thailand and the Philippines. It currently owns interests in three producing properties in Salawati Basin, Salawati Island and Jambi; two new oil field developments projects are also underway in Sumatra and Thailand, which should both commence oil production in 2005 and will increase considerably the size of the business. The company also has an extensive inventory of contingent resources and exploration prospects.

Meanwhile, ChevronTexaco has sold its Singapore Syngas subsidiary to Linde of Wiesbaden, Germany, for an undisclosed sum. Singapore Syngas operates one of the world's largest gasification plants for generating hydrogen and carbon monoxide, as well as a high-performance air separation unit.

Staying downstream, ChevronTexaco's wholly owned subsidiary Caltex Singapore has acquired half of BP Singapore's one-third equity interest in the Singapore Refining Company (SRC) to become a 50:50 joint owner in the refinery with the Singapore Petroleum Company (SPC).

SOUTH KOREA

Gazprom and Kogas have discussed the possibility of Russian natural gas exports to South Korea, considering the prospects of bilateral cooperation and agreeing on further negotiations on gas supplies and the drafting of a contract within a joint working group. South Korea has very limited gas resources but has just started up production from the 250bn cf Donghae field. The country is almost totally dependent on LNG imports, importing some 18mn tonnes in 2003.

A proposed pipeline to carry gas from Siberia's Kovykta gas field to South Korea and China is expected to cost in the region of $11bn. Partners include Kogas, Rusia Petroleum (in which BP holds a 30% interest) and CNPC. Kovykta reserves are put at 840mn tonnes of gas. It is thought that the field could supply some 7mn t/y of gas to South Korea for a 30-year period, with a further 14mn t/y being supplied to China. However, Kovykta is not expected onstream before 2008 at the earliest.

Japan is reported to be interested in combining the route of an oil pipeline from Taishet to the Sea of Japan with the Kovykta gas pipeline in a bid to cut construction costs by nearly 50%. The building of the pipeline to transport some 80mn t/y of Russian oil to the Asia-Pacific through a terminal on the Sea of Japan coast has been estimated at $16.22bn. The pipeline is to pump 24mn tonnes of oil from Western Siberia and another 56mn tonnes from fields in Eastern Siberia and the Russian internal republic of Sakha (Yakutia), most of which have yet to come onstream. China will initially receive 12bn cm/y of gas and South Korea 10bn cm/y. China will buy another 8bn cm annually for Beijing and its hinterland from 2013.

In other news, LG Caltex Oil Corporation of South Korea has received permission from the Korean Ministry of Commerce, Industry and Energy to directly import LNG. The company expects to be importing 1.5mn tonnes of LNG by 2008 in Yosu, at an already existing refinery. Meanwhile, as already mentioned (see Indonesia – p19), South Korean steel manufacturer Posco has signed a deal with the BP-led Tangguh LNG consortium to import 550,000 t/y of LNG over 20 years, beginning in 2005. Posco, which is investing $290mn in a 1.7mn t/y LNG import terminal at Gwangyang, will be the first company other than state-owned Kogas to import LNG into Korea.

More recently, the labour union at state-owned Kogas was reported in September to have issued a statement rejecting sweeping government reforms that would allow the entrance of private players into the domestic gas sector. The announcement comes hot on the heels of a recent failed attempt to privatise the six generating companies of the government-run Korea Electric Power Corporation. Korea currently imports its entire supply of gas. Kogas is the sole importer and distributor. According to the union, the entrance of more players would lead to fragmentation of the market.

Meanwhile, Sinochem is set to become the first Chinese company to enter the South Korean oil market once it completes its planned $562mn acquisition of South Korea's bankrupt Inchon oil refinery. The refinery has a capacity of some 275,000 b/d, but has only been operating at 30% capacity since its bankruptcy in August 2001.

SRI LANKA

International law firm Reed Smith LLP recently secured the legal work on a major oil refinery and a co-generation power project being developed by Regional Cooperative Petroleum Refinery (RCPRI) in Sri Lanka. RCPRI is a consortium of a leading local developer and some major international contractors/investors.

The project is one of the largest infrastructure/commercial projects in the Indian-Sub Continent with a capacity to refine 200,000 b/d. The project is expected to cost approximately $2.3bn to complete and is forecast to contribute as much as 11% of the total GDP of Sri Lanka.

Sri Lanka is expected to call its first bidding round for oil exploration in 1Q2005. Eight blocks are to be offered in the Mannar Basin that is thought to hold up to 50mn barrels of reserves.

TAIWAN

(See also *Petroleum Review*, January 2004.)

Chinese Petroleum Corporation (CPC) has outlined plans for the construction of what will be Taiwan's second LNG receiving terminal. The facility will be sited on the western side of the island, in the port of Taichung, and is due to be commissioned in 2009. It will have an annual throughput capacity of 3mn t/y and is likely to cost in the region of $720mn.

CPC and Taiwan Power have a 25-year LNG supply agreement under which CPC will start feeding gas to Taiwan Power's new 4,272-MW Tatan power plant from the LNG terminal in northern Taiwan starting in 2011. CPC will supply 1.68mn t/y of LNG to Taipower under the deal and has committed to lifting 3mn t/y of LNG from the RasGas II project to supply Taipower's Tatan requirements.

THAILAND

Strong economic growth of some 6% in 2003 is driving gas demand in Thailand. Unocal is the main gas producer in the country. The continued development of ChevronTexaco's fields in the northern Gulf – Jarmjuree, Tantawan, Benchamas and Maliwan – is contributing most of the incremental oil production.

Photo: David Hayes

Thai oil production is forecast to grow to around 620,000 b/d by 2008, with gas production of some 480,000 boe/d.

The most recent licensing round was

in July 2003, in which exploration rights in eight onshore and offshore blocks were awarded to seven international companies, including ChevronTexaco, Shell and CNPC of China. However, according to Scottish Development International, the 19th round is not anticipated until after 2005 as the government is evaluating reserves and amending the bidding conditions to match market reality.

A number of gas-based projects are due onstream from 2006 onwards, including PTTEP's Arthit field in blocks B14A, B15A and B16A. Development will be via a production platform with five associated wellhead platforms and 66 appraisal/development wells. First gas is expected in mid-2006 at a rate of 330mn cf/d. Reserves are put at 7tn cf.

Thailand and China are reportedly planning to discuss investment opportunities in the strategic energy land bridge (SELB) project, part of Thailand's initiative to become a regional energy hub. The project involves the construction of a 2mn b/d, 250-km oil pipeline from Phangnga, located on the Andaman Sea in southern Thailand, with Sichon, located off the Gulf of Thailand; construction of oil loading and offloading facilities at either end of the pipeline; construction of storage terminals and berthing facilities. China, Japan and Oman are understood to have expressed an interest in participating in the project, which, once completed, will provide oil traders a shorter alternative to the congested Straits of Malacca.

In other news, state-run Electricity Generating Authority of Thailand – the country's largest natural gas consumer – is reportedly planning to launch a feasibility study on LNG imports. Natural gas accounts for 60%–70% of EGAT's total fuel mix for power generation. The utility currently consumes around 2bn cf/d and is forecast to grow at an annual rate of 6%–7% over the next few years. Meanwhile, Thailand's state-owned oil company PTT, which has a monopoly on domestic gas distribution, is understood to be conducting a separate study to determine if LNG is a more viable option for Thailand compared with bringing pipeline gas from fields in the region. Thailand currently holds around 13tn cf of proven gas reserves, all of which is located in the Gulf of Thailand. Besides using indigenous gas, the country also imports natural gas from Myanmar.

Negotiations are also reported to be underway between PTT and Sinopec regarding a proposed joint venture in an oil pipeline project that aims to reduce the costs of shipping oil from Thailand to northern and eastern Asia. The pipeline will run from the southern island of Phuket, taking crude oil and petroleum products to be loaded on tankers and shipped to the northeastern and eastern markets, including China and Japan.

More recently, Unocal announced that it had completed successful delineation drilling in the South Gomin operating area in block 13 in the Gulf of Thailand. The drilling programme involved three follow-up wells that encountered 195, 183, and 95 ft of net natural gas pay. First production from South Gomin is expected in late 2006.

VIETNAM

Exploration results in Vietnam continue to be mixed due to poor reservoir quality and fields that are generally smaller than expected, comments Scottish Development International. Production has rapidly increased since 1986 and is expected to continue to increase over the next few years. However, fields will get smaller and more complex, and decline is expected to begin towards the end of the decade. New gas markets will also be required to develop additional gas beyond that already being produced by BP's Nam Con Son project, which is producing some 3bn cm/y of gas from the Lan Tay and Lan Do fields in its first phase of development.

Photo: ConocoPhillips

Thailand's state-owned PTT is understood to have signed a memorandum of understanding with Petrovietnam to jointly study the possibility of constructing a natural gas distribution pipeline system in southern Vietnam. The companies plan to set up a joint working group to look into the feasibility of the project, initially focused on 12 industrial zones of Ho Chi Minh City. The study is expected to be completed by 2005. This is reported to be the first time that PTT has ventured outside Thailand to invest in gas distribution pipelines.

In 1Q2004, Vietnam produced more than 1.6bn cm of gas, the Nam Con Son Basin off southern Vietnam accounting for some 282.4mn cf/d of production. Most of the Nam Con Son gas is currently used for power generation by state-owned Electricity of Vietnam. However, the government is trying to promote natural gas as a fuel of choice for the industrial sector.

In May Petrovietnam and PGS Geophysical signed a cooperation agreement granting PGS exclusive rights to acquire a multi-client 3D (MC3D) seismic survey over open block 06/94 in the Nam Con Son Basin offshore Vietnam. Block 06/94, located immediately south of the Lan Tay and Lan Do gas fields, is to be included in the 2005 bidding round that is expected to be formally opened by Petrovietnam in 4Q2005.

Earlier in the year, tests at Vietnam's Su Tu Trang (White Lion) field in block 15.1 in the Cuu Long Basin were 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.

In other news, the Vietsovpetro Russian-Vietnamese joint venture discovered oil deposits on Vietnam's continental shelf, within the boundaries of section 09-1 of the Dragon oil field that is currently being developed by the joint enterprise. It is estimated that the new well is capable of producing 1,100 b/d of oil.

The December issue will review the latest E&P developments relating to Australia and New Zealand. It will also take a closer look at activities in Malaysia.

Country/Field	Operator	Disc.	Oil or gas output	Start-up date	Oil res. (mn b)	Gas res. (bn cf)	Capex ($mn)	Production system
BANGLADESH								
Bibiyana (block 12)	Unocal	1998	gas/cond	2009		6,000	341	onshore
Moulavi Bazar (block 14)	Unocal	1999	gas	2006		400	70	onshore
Shahbazpur	Unocal	1995	gas	2006		333		onshore
BRUNEI								
Bugan	BSP	1993	gas			140		
Egret Phase 1	BSP	1971	oil/gas	2006	50	700		12-slot platform
Kikeh (see Malaysia)								
Mampak	BSP	1997	oil/gas	evaluation				
Merpati	BSP	1992	gas	evaluation				
Seria North Flank	BSP	2004	oil	incr reserves	+100			
CHINA								
Bajiaochang (Sichuan) gas	Burlington		gas	go-ahead given				
Bonan fields (Bohai Bay)	CNOOC		oil/gas	2005	30	300		
Bozhong 25-1	CNOOC		hvy oil	3Q2004	350			FPSO
Caofedian CFD 11-1, 11-2 (Bohai B)	Kerr-McGee/CNOOC	1999	oil	Jul-04	130			FPSO + 2 platforms
Changbei (Ordos Basin)	Shell		gas	2006+		2,500		onshore
Cheng Dao Xi (Bohai Bay)	Noble Energy	1998	oil	Feb-03	30			platform 11 wells
Chuanzhong block (SW China)	Burlington		gas	2005		1,000		
Chunxiao (East China Sea)	CNOOC Ltd.		gas					under development. dispute with Japan
Daniudi (Inner Mongolia)	Sinopec		gas	Jun-09		8,800		pipeline to Shandong
Dongfang 1-1 (S China Sea)	CNOOC	1992	gas	2003		1,750		
East China Sea fields	CNOOC		gas/cond	2005	30	1,500		
Erdos Basin, Inner Mongolia	PetroChina	2002	gas			21,268		
Futai (Shengli area)	Sinopec	2000	oil		160			
Huizhou 19-1/2/3 (S China Sea)	CACT	2000/2001	oil	2004	60			
Huizhou 21-1 (S China Sea)	CACT	2000	gas/cond	2006	10	115		
Jinzhou 21-1 (Bohai Bay)	CNOOC	2000	oil/gas	2008	7	60		
Kela-2 (Tarim Basin)		1998	gas			7,500		
Luda 4-2 (Bohai Bay)	CNOOC	2002	hvy oil	2005	90			
Luojiazhai +3flds (Sichuan)		2002	gas	2005		5,600		
Lungu (discovery in Tarim)	Petrochina	2001	hvy oil		500			onshore
Mosuowan	PetroChina		gas/oil		150			
Nanbao 35-2	CNOOC	1996	hvy oil	2005	110			platform
Panyu 4-2/5-1 (S China Sea)	Devon Energy	1998	oil	Oct-03	90			FPSO + 2 wellhead plats
Panyu 19-3 1	CNOOC	2002	gas					
Panyu 30-1 1, 34-1 1	CNOOC	2003	gas			1,500		
Pearl River Mouth fields	CNOOC	2001/3	gas	2006/2007		1,500		
Peng Lai 19-3 (Bohai) Ph2	ConocoPhillips blk 11-05	1999	oil	2007		as above		mltple plats, cent process
Qikou 18-2 (Bohai Bay)	CNOOC	1995/2000	oil/gas	Jun-04	9	10		
Sulige (Ordos Basin)	PetroChina	2001	gas			11,800		
Tainan (Qaidam)			gas			3,400		
Tarim Basin 13 fields			gas			13,200		
Tarim Basin Kela 2			gas			10,000		
Weizhou 11-1 (Beibu Gulf)	CNOOC	2004	gas/oil	discovery				
Weizhou 12-1 (Beibu Gulf)	CNOOC	1999	oil	Jun-04	30			
Wenchang 8-3/19-1	CNOOC	1986/1994	oil	2005	40			
Zhao Dong (Bohai Bay)	Apache/PetroChina	1994	oil	Aug-03				2 platforms 17 wells
INDIA								
Bombay Offshore	ONGC	1974	oil/gas	1976	5,500	15,800		offshore
D6 (Krishna Godavari Basin)	Reliance Industries		gas	Aug-06		14,500		offshore
Dhirubhai (Krishna Godavari Basin)	Reliance Industries	2002	Gas	2005		7,000	2,573	offshore
Gauri	Cairn Energy	2001	oil/gas	2004		92	88	platform T/bk to Lakshmi
Mangala (Northern Rajasthan)	Cairn Energy	2003	oil	late 2007	100–275			
NA	Cairn Energy	Mar-04	oil	eval	130–470			
NB	Cairn Energy	Feb-04	oil	eval	400			tested 6,000 b/d
NC or NV	Cairn Energy	Apr-04	oil	eval	300			
Orissa coast Bay of Bengal	Reliance Industries	Jun-04	gas	discovery		4,000–5,000		
Panna & Mukta	BG-ONGC-Reliance	1976	oil/gas	1986	180	550	751	offshore
Panna expansion	BG-ONGC-Reliance	1976	oil/gas	3Q2005	18	74		2 wllhd plats, 11 horiz wells
PY-1	Mosbacher Energy	1980	gas/cond	2005		230	97	onshore platform
INDONESIA								
Banyu Urip (Cepu block)	ExxonMobil	2001	oil/gas	2005?	600–1000			platform +FSO
BD (Madura)	ExxonMobil	1987	gas/oil	2005+	20		310	platform
Belanak (blk B W. Natuna Sth Chi Sea)	ConocoPhillips	1975	gas/oil	Dec-04	75.2	500		FPSO (100kb/d+gas)
Block A, North Sumatra	ConocoPhillips		gas	2005+		476	240	onshore to fertiliser plt
Cepu	ExxonMobil		oil	??		250		operator post 2010 negs.
Donggi and Senoro (Sulawesi)	Pertamina/Medco En.	1999/2001	gas	2007+		4,000		
Gajah Baru (New Elephant)	Premier Oil	2000	gas	2005+				Natuna Sea no sales cont
Gehem (Offshore E Kalimantan)	Unocal	2004	gas	evaluation		1,500		joint develop. Ranggas
Gendalo Phase I	Unocal/Eni		gas	2007				
Jabung (Makmur, N Geragai)	Petrochina	1995/1996	oil/gas	2003				
Kerisi	ConocoPhillips	1990	oil	2005				
Merah Besar	Unocal	1996	oil/gas	2005+	52	160		mini TLP to West Seno
Natuna D Alpha	ExxonMobil	1973	gas	2010+		46,000		16 platforms
Nubi/Sisi	TotalFinaElf	1986/1992	gas	2007	40	2,700	200	plat joint dev
Oyong (gas)	Santos	2001	gas	2005+		90		
Ranggas (off Kalimantan)	Unocal	2000	oil	evaluation	400	2–350m boe		Joint develop. Gehem
Singa in Sth Sumatra	Exspan	1997	gas	2005+		400		onshore

Table 2: Current and planned key field developments in the Asia-Pacific region

Country/Field	Operator	Disc.	Oil or gas output	Start-up date	Oil res. (mn b)	Gas res. (bn cf)	Capex ($mn)	Production system
Sirasun/Terang	BP		gas	2005+		800	500	subsea via Pagerungam
Sungai Kenawang	Repsol/YPF	2002	gas/cond					test 380,000 cm/d, 370 b/d
Tangguh (Weriagah)	BP	1990–1997	gas/oil	2007	80	18,300	1,750	onshore, platform
Ujung Pangkah	Amerada Hess	1998	gas/oil	2005+	450 in place	478		
West Seno Phase I	Unocal	1998	oil/gas	Aug-03	250	180		TLP FPSO
West Seno Phase II	Unocal	1998	oil/gas	2005	250	180		second TLP poss delays
Donggi and Senoro	Pertamina and Exspan		gas			5,000		onshore
JAPAN								
Sado Island (offshore)	Japan Enrgy/Idemitsu		oil/gas	2008				
MALAYSIA								
Ansi Sth/Sth Angsi (block PM-305)	Talisman Energy	2003	oil	mid-05	18–25			
B12, off Sarawak	Sabah Shell?	1971	gas	2005		500		platform
E6, off Sarawak	Sabah Shell Carigali		gas					
E8, off Sarawak	Shell/Petronas Carigali		gas	2005		2,100		platform + compression
F13, off Sarawak	Shell/Petronas Carigali		gas	2009		3,100		platform + compression
F14, off Sarawak	Shell/Petronas Carigali		gas					platform
F28, off Sarawak	Shell/Petronas Carigali	1981	gas					platform
F29, off Sarawak	Shell Malaysia	1980	gas	post-2010		100		platform
G7, off Sarawak	Shell Malaysia		gas	post-2010		100		
M3 South, off Sarawak	Shell Malaysia	2004	gas/cond	2005				
Belumut	EPMI	1970	oil	2004	11		50	platform
Beryl	Petronas Carigali	1969	gas	post-2010		400		platform
Bintang	Esso Malaysia	1970	gas/oil	Feb-03	25	1,000	250	platform
Blocks PM 5,8,9,10	Esso Malaysia		gas	1998 onwards				Peninsular gas project
PM3 CAA Phase II	Talisman			Sep-03				platforms
Bunga Orkid	Talisman	1991	gas/oil	2007	3	415		platform
Bunga Kamelia blk PM 301	Shell/Petronas	2003	gas	discovery		200 in blk 301		
Bunga Zetung blk PM 301	Shell/Petronas	2004	gas	discovery		200 in blk 301		
Cendor (PM 304)	Petrofac (ex Amerada)			late 2006/2007				
Congkak	Murphy Oil (SK 309)	2002	oil					
Guntong E (production hub)	ExxonMobil		gas	2006				platform, gas processing
Gumusut (deepwater block J)	Shell	2004	oil	discovery				
*Helang (blk SK 10)	Nippon Oil Explor.	1990	gas	2003		1,600		platform
*Jintan (blk SK 8)	Shell	1992	cond/gas	Sep-04	56	2,800		unmanned plat. to M1
Kikeh (blk K, off Sabah)	Murphy/PetronasCar.	2002	oil	2007	700			
Kebabangan-3 (discovery)	Open - Petronas	2002	oil	test 10,000 b/d				
Kenarong-1 (PM 311 offsh Pen. Malay)	Murphy Oil	2004	oil/gas	discovery				
Laila	Petronas Carigali	1999	gas	2010		300		platform
Serai (blk SK8)			gas	Jun-04				
*SK8 other fields	Shell	1993/4	gas/cond	2004 onwards	31	2,400		platform
*SK10 other fields	Nippon Oil	1991	gas/cond	2012	4	100	37	subsea tie-back to Helang
West Patricia (off Sarawak)	Murphy Oil (SK 309)		oil	May-03	38			
MALAYSIA-THAILAND JDA								
Cakerawala	CTOC	1995	gas/cond	1H2005	51	2,100	800	platform
A18 fields	CTOC	1995	gas/cond	2005	100	5,200	1,230	Cakerwala is phase1
B17 fields	CPOC	1995	gas/cond	2011	57	1,600	780	Muda plat + pipeline link
KOREA (SOUTH)								
Donghae (East Sea)	KNOC	2002	gas	Apr-04		250		3 subsea to prodn plat
MYANMAR								
Block A-1	Daewoo Intnl	2004	gas	2006–2007		4,000–6,000		
PAKISTAN								
Bhit	Eni	1997	oil/gas	2003		896	340	onshore
Sawan	OMV	1998	gas	Nov-03		1,300	329	onshore
Zamzama	BHP Billiton	1998	gas/cond	2001/03		1912	420	onshore
PHILIPPINES								
Malampaya (oil)	Shell	1992	gas/cond	2002	80	3,100		subsea tie-back
THAILAND								
Arthit (B14A, B15A, B16A)	PTTEP	1999	gas/cond	2Q2006	40	3,200		5 wellhd plats + prodn plat
Bongkot redevelop 3C	PTTEP		gas/cond	2003	6	500		plat + gas processing
Lanta (G4/43)	ChevronTexaco	2004	oil/gas	discovery				
North Jarmjuree	Chevron	1992	oil/gas	2003	65	400		discovery
Dara	Unocal	1974	gas/cond	2011	14	160		
South Gomin block 13	Unocal	2004	gas	2006				
VIETNAM								
Bunga Kekwa PhII	see Malaysia							
Hai Thach	BP	1995	gas/cond	2007	90	1800		platform
Lan Tay/Lan Do	BP/Statoil	1993	gas/cond	2002	10	1,600	1,230	two platforms
Rong Doi	KNOC	1995	gas/cond		12	800		platform
Su Tu Den (Black Lion) blk15-1	Cuu Long Op Co	2000	oil	Oct 2003	400			FPSO (70kb/d)
Su Tu Vang (White Lion) blk 15-1	Cuu Long Op Co	2001	oil	2008	220+			FPSO
Song Doc blk 46/02	Truong Son Jnt Op Co	2003	oil	disc.	test 7,300 b/d			

Key: *to Tiga LNG project

Current and planned key field developments in the Asia-Pacific region *Source:* Petroleum Review

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BTC blend – a future marker crude?

Exports from the Baku-Tbilisi-Ceyhan (BTC) pipeline are currently forecast to commence in 3Q2005. Initially the line will predominantly carry Azeri Light oil, but is likely to include increasing quantities of Kazakh oil – especially as the Kashagan field ramps up. There has been some discussion in the market recently regarding the potential for this sweet crude oil to develop into a marker grade in the next few years. *Ben Holt*, Associate Director, Channoil Consulting,* reports.

All photos: Pipes and construction underway on the BTC pipeline right of way, north of Goksun, Turkey
© BP Plc 2004

The chances of BTC blend becoming a marker grade in the future can be better assessed by considering a number of criteria typically associated with marker crude oils. These are:

- Large export quantities.
- Large number of equity participants and no threat of abuse of a dominant position.
- Quality – refining characteristics which allow the grade to be consumed by a wide range of refineries.
- Logistics – the ability to load large cargoes to facilitate arbitrage to more distant markets.
- A broad demand market.
- Terminal operator with flexibility, transparency and equitability in cargo scheduling.
- Upstream fiscal, commercial and political conditions that do not inhibit spot sales but do encourage forward trading by producers.
- Willingness of trading companies to participate.

Let us consider each of these in turn:

Export quantity

The BTC pipeline will initially have a capacity of 500,000 b/d, increasing to 1mn b/d by 2008. The principal supply to this line, at least initially, will be the BP-operated ACG field complex in the Caspian Sea offshore Azerbaijan. This is thought to contain at least 5.4bn barrels of recoverable oil. Exports for the field are currently via the 'Western Route' export pipeline to the Georgian Black Sea port of Supsa (120,000–140,000 b/d) and via a 'Northern Route' to another Black Sea port, Novorossiysk in Russia. The latter is less used, principally due to the value loss incurred in blending sweet Azeri oil with Urals Blend. However, Socar is continuing with the route for political reasons – although its intergovernmental agreement for 50,000 b/d expires next year.

Once the BTC commences operation, production from ACG is expected to reach 400,000 b/d during 2005. Exports via Supsa are, however, expected to continue. The Western Route is a cheap path to market and provides a strategic alternative to the BTC pipeline, especially for those such as ExxonMobil who did not invest in BTC. So, Azeri exports from Ceyhan may initially be limited to around 200,000–250,000 b/d.

The second phase expansion of the ACG field, already sanctioned, is expected to bring production up to 800,000 b/d in 2007, implying Ceyhan exports of at least 650,000 b/d. Output is expected to further increase to around 1mn b/d in 2010.

In addition to ACG oil, the pipeline is likely to carry a number of other, predominantly light, crude oils in due course. The principal increment is likely to come from Kazakhstan. The giant Kashagan field – expected to produce at a rate of 1.5mn b/d by the middle of

API gravity	34.9
Total sulphur	0.14% mass
Pour point	–6°C
Viscosity	5.03 cst at 50°C
TAN	0.35 mg KOH/g
Nickel	3 ppm mass
Vanadium	<2 ppm mass

Table 1: Blend quality *Source: Statoil*

Company	BTC stake (%)	ACG stake (%)	Kashagan stake (%**)
BP	30.10	34.10	–
Socar	25.00	10.00	–
Unocal	8.90	10.30	–
Statoil	8.71	8.70	–
TPAO	6.53	6.70	–
Total	5.00	–	20.37
Eni	5.00	–	20.37
Itochu	3.40	3.90	–
Inpex	2.50	10.00	8.33
ConocoPhillips	2.50	–	10.19
Delta Hess	2.36	2.70	–
ExxonMobil	–	8.00	20.37
Devon	–	5.60	–
Shell	–	–	20.37
	100	100	100

***Assuming BG-proposed sale of interests to partners is completed (see p12)*

Table 2: Most likely users of the BTC pipeline

the next decade – starts up in 2008 and some of its partners, such as Eni, ConocoPhilips and Total, have equity interests in BTC.

Smaller volumes of other Kazakh grades such as Kumkol could be transported even earlier, however. Intergovernmental agreements are in preparation for Kazakh volumes of 40,000–80,000 b/d from 2008, rising to 200,000 b/d by around 2011. These would most likely be moved by tankers from Kuryk, 70 km south of Aktau, or via the Russian Caspian port of Makachkala, to Dubendi/Baku. From there the oil could either be used for local refining, freeing up other Azeri domestic production for export on a swap basis, or injected directly into BTC.

Further, smaller, volumes could be supplied from Turkmenistan – although Iran offers an attractive and politically acceptable outlet for much of this at present. Russia is unlikely to be a significant user of BTC for political reasons.

Concerns were expressed in the Brent market over the blend's ability to provide sufficient liquidity for a forward market when production volumes fell below 500,000 b/d, at the start of this decade. This led to the introduction of the Brent/Forties/Øseberg (BFO) contract in 2002. It appears likely that BTC exports will start to exceed this level of 500,000 b/d from around 2007. By 2010 production of both Brent Blend and Øseberg – currently the main price-setting grades in BFO – may be only 100,000–150,000 b/d, while exports of Forties Blend (net of consumption by BP's Grangemouth refinery which is fed by the Forties System) may be at similar levels, so a search for a new sweet Atlantic Basin international marker grade with liquidity will be on.

Wide range of sellers

The equity investors in BTC, having access to a preferred tariff and needing to ensure finance payments are covered, are the most likely users of the line. But several other companies may use the route for at least a part of their production. **Table 2** shows the most likely users.

A wide spread of equity interests among exporters is seen as positive for the prospects for trading liquidity and lack of trade dominance. The spread of equity producer interests in BTC blend is likely to be good in that the largest player, BP, will hold only around one-third of output, and a further dozen or more companies shown in **Table 2** may well have entitlements close to one parcel of 600,000 barrels each month.

Blend quality

Initially, BTC blend will predominantly comprise Azeri Light crude oil. As exported today, this is a relatively widely acceptable crude oil grade. Its principal qualities are shown in **Table 1**.

It is a medium-gravity, low-sulphur crude with no physical handling problems. Its naphtha is of good reforming quality, while its jet fuel and diesel products meet normal smoke point, cetane and cold property specifications. It makes good cracker feedstock. The only potential disadvantage for some potential refiners is marginally high acidity, which may imply a need for dilution before running on unprotected mild steel units.

The quality of BTC blend oil would clearly evolve with addition of Kazakh or other oils. A pipeline inlet specification and a quality bank system has been agreed by owners to govern the main properties such as sulphur content. Kashagan crude oil is reportedly light at 42–46° API gravity. Kumkol is already well known in the market as a very high quality grade.

Loading logistics

Expansion of the Ceyhan terminal will allow simultaneous loading of two VLCCs of up to 300,000 tonnes deadweight (around 2.25mn barrels), from seven crude oil storage tanks, together with waste water treatment and recovered vapour incineration.

Thus it should be possible to load a wide range of tankers with BTC blend for worldwide destinations. The minimum cargo size at Ceyhan will be 600,000 barrels.

Broad demand market

Certain ACG equity producers have taken the opportunity of limited exports from Supsa to build the market for Azeri light oil before volumes increase further. In the Mediterranean, 50,000 b/d went to Italy last year, and significant quantities are also imported via Trieste for Germany, the Czech Republic and Austria. Turkish and Balkan refiners have regularly sought it for its low sulphur content.

This year, at least four cargoes have also gone to north-west Europe. Several cargoes have also gone into Indonesian tenders – with at least three Suezmax cargoes going East already during 2004. Limited volumes have gone to US Atlantic Coast refiners in the previous years.

Terminal operator
Prospects for trading of a grade are appreciably enhanced if all lifters, equity or otherwise, are treated equitably in scheduling and adjusting off-take programmes. The operator should adhere to pre-agreed procedures in its activities, allowing flexibility in combining parcels and adding top-up volumes where operationally possible, and reacting fairly to rescheduling problems, while protecting the commercial rights of equity off-takers.

BP is expected to establish a separate unit in London – similar to its current North Sea off-take scheduling activities, to run these operations – so similar standards of operation can be anticipated.

Upstream situation
It is probably no coincidence that marker crudes have tended to develop in free market environments such as the UK, the US and Dubai, where trading is seen as positive for the economy. Certain other host governments such as large Opec producers would be unlikely to support price benchmarks on their own crudes. This seems unlikely to be a barrier here.

Fiscal terms and production sharing contract provisions for assessing the basis of revenue obtained from sales of oil play an important part in influencing the pattern of trade.

Whether the host government regime relies mainly on a tax regime, as in the UK, on a production sharing contract or other basis, it is always necessary to have a means to measure the revenue obtained by a producer through sales of oil as an input to the determination of its profit or degree of recovery of past costs. In the UK, it is possible to be assessed for tax based on the actual price obtained for a sale to a third party, providing the producer with tax certainty. UK Brent trading was stimulated, though not initiated, due to the advantages for major players of selling spot at fixed prices. In Norway, on the other hand, equity producers, especially those with few cargoes each month, have been reluctant to make fixed price sales because they are taxed based on an average price for the month. Smaller producers have tended to attempt to make sales based on average price formulae that mirror the expected taxation basis.

We at Channoil Consulting understand that, at least for Azeri oil, production sharing contract terms allow for assessment of a producing company's revenue from arms-length sales on the basis of the actual sale price for the cargo. This may be a key element encouraging companies to sell at fixed prices and contribute to price setting, rather than indexing the price of their oil to other, sometimes poorly related and geographically remote, market benchmarks.

Traders willing to play?
If the above conditions are positive for forward trading, then trading companies are likely to participate. They will want to be satisfied that there is a level playing field for trade, with no dominant players exercising commercial advantage against them.

Most important is an expectation that they will normally be able to cover a short position without being squeezed. The spread of equity interests in BTC blend suggests this should not be a problem.

There may well also continue to be opportunities to purchase on a term or tender basis from certain players.

The road ahead

It would appear that the quality, quantity, ownership, upstream commercial and logistic base seem favourable for a new benchmark crude, especially from around 2010 when volumes will have built up to around 1mn b/d.

However, whether BTC blend would achieve marker status in parallel with Brent or as a successor remains to be seen.

**Further information can be obtained by visiting* www.channoil. co.uk *or* e: consult@channoil.co.uk

Reservoir Microbiology Forum

The next meeting of the Microbiology Committee of the Energy Institute and the Reservoir Microbiology Forum is 29-30 November and the subject of this year's forum is Produced Water Reinjection and Oilfield Microbiology.

Due to increasingly stringent environmental regulations, produced water reinjection (PWRI) is becoming more and more widespread. With the implementation of PWRI come new challenges for the oilfield operators.

Topics of discussion at this year's forum includes microbial problems associated with produced water reinjection, advances in monitoring techniques, prediction and modelling of produced water reinjection, and mitigation strategies.

For more information, please contact Martin Maeso at e:**mmaeso@energyinst.org.uk**

Synfuel excess

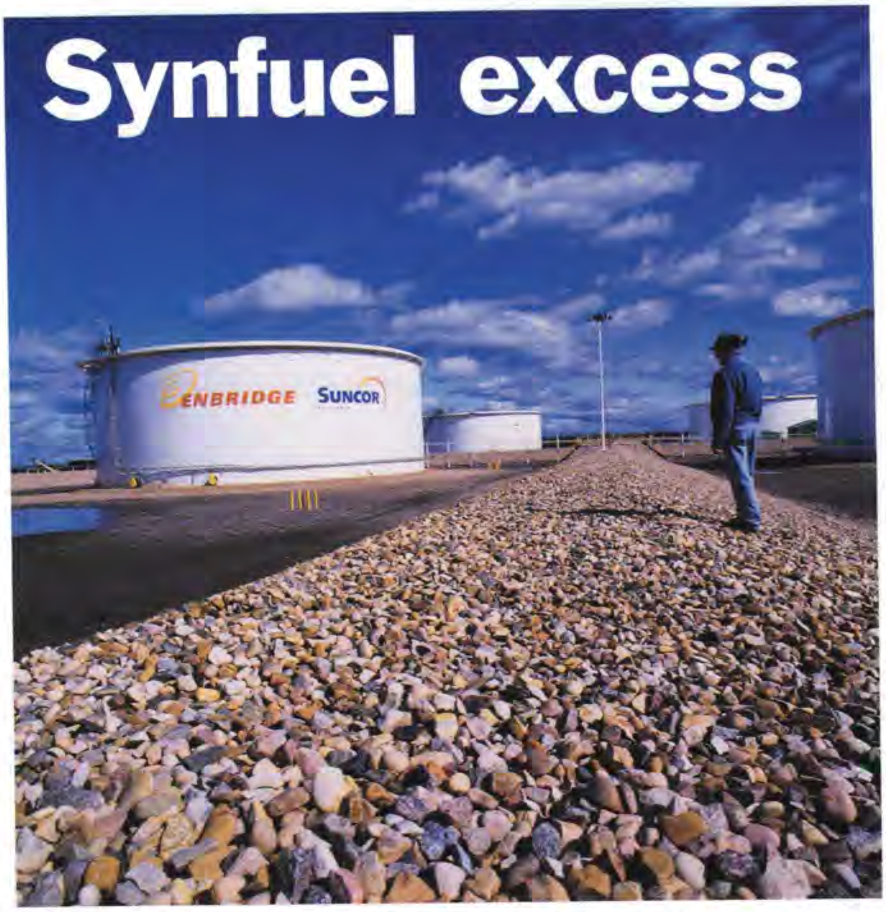

Photo: Suncor

Oil sands tanks, Canada

As Canada's conventional crude supplies dwindle, the vast bitumen deposits of Northern Alberta are seen as a solution to the petroleum industry's woes. But with a host of recent ills plaguing their development, will the oil sands turn into quicksand? asks *Gordon Cope*.

The oil sands are located in north-east Alberta, around Fort McMurray. Alberta's Energy and Utilities Board (EUB) places recoverable reserves at 175bn barrels. Since the 1960s, the oil sands have been exploited through large-scale mining operations in which the boreal overburden is scraped away and the mixture of bitumen, water and unconsolidated sand is dug out by shovel. However, because 80% of the reserves lie too deep for open pit mining, they are being increasingly recovered using in-situ techniques such as steam assisted gravity drainage (SAGD), in which steam is injected into the ground in order to decrease viscosity and encourage the bitumen to flow to the surface.

Unlike the uncertainty that surrounds the exploration for conventional crude production, exploiting the oil sands carries little risk. For the last few years, major petroleum companies have been investing an average of C$6bn annually into production facilities. The National Energy Board (NEB) reports that oil sands production will hit 1mn b/d this year, accounting for about 40% of Canada's production of 2.5mn b/d.

Of the three major projects currently operating, Syncrude is the largest. Owned by Canadian Oil Sands Trust, Imperial Oil, Petro-Canada and Nexen, it produces an average of 250,000 b/d of light, sweet crude oil called Syncrude Sweet Blend (SSB) from its Mildred Lake and Aurora facilities located north of Fort McMurray. Its multi-stage expansion, Syncrude 21, is now in the third stage. Pegged at C$7.8bn, Stage 3 will boost output by 100,000 b/d to 350,000 b/d by 2006.

Suncor, the oldest commercial mining operation, produces 220,000–225,000 b/d of synthetic crude after its latest expansion, the C$3.4bn Millennium project, which completed in 2002. In addition, Suncor produces around 15,000 b/d from the partially completed Firebag project, an in-situ operation located 40 km north-east of its main facility. Once completed, Firebag should add 35,000 b/d, boosting total production to 260,000 b/d in 2005.

Shell Canada, Chevron Canada Resources and Western Oil Sands jointly own the Athabasca Oil Sands Project (AOSP), which extracts 155,000 b/d from its Muskeg River mine, located 70 km north of Fort McMurray. The bitumen output is mixed with diluents, and the 'dil-bit' slurry is transported 490 km by pipeline to Edmonton, where it is upgraded to refinery feedstock.

All three projects have extensive enlargement plans. AOSP intends to spend C$2bn to expand its Muskeg Mine and Scotford upgrader by 70,000 b/d to 225,000 b/d. Suncor's next phase of growth is Voyageur – an expansion of in-situ production and upgraders that will increase oil sands output to as much as 555,000 b/d (see box piece). Syncrude will spend C$1.5bn on Stage 4, scheduled to raise production to 425,000 b/d. Stage 5, targeted for 2015, will boost production to around 550,000 b/d.

Above and beyond the major three, the Canadian Association of Petroleum Producers (CAPP) predicts that C$30bn will be spent on new projects and infrastructure in the coming decade. The EUB recently approved Canadian Natural Resource's Horizon oil sands project, a C$8.5bn endeavour that will produce 232,000 b/d of synthetic crude by 2008. Meanwhile, Imperial Oil and ExxonMobil want to build an open pit mining operation at Kearl Lake, about 60 km north of Fort McMurray. The C$8bn project could see first production of 100,000 b/d in 2007, with the potential to expand to 200,000 b/d at a later date. Husky Energy will launch its Tucker oil sands project in 2005. The C$500mn in-situ project will use steam to produce 35,000 b/d by 2006. Shell Canada has received regulatory approval for Jackpine, a 200,000 b/d project near the Muskeg River mine. It includes an oil sands mine and bitumen extraction plant. Timing for what will be a multi-billion dollar project has yet to be set.

According to studies done by CAPP, oil sands expansion will far surpass the expected decline in Western Canada's production of conventional oil. 'CAPP's production/supply forecast points to a potential increase in supply of crude oil of 1mn b/d over the next 15 years, ie until 2015,' says Onno Devries, General Manager of Oil Sands for CAPP.

Crude accusations

However, there are many obstacles that can come between dreams and reality. First and foremost are the gargantuan cost overruns that have arisen over the last two years. For example, Suncor's Millennium expansion, which was originally tipped at C$2bn, ended up costing C$3.4bn when it finished in 2002. Shell Canada's Athabasca Oil Sands Project ended up costing C$5.2bn, 33% higher than original estimates, when it opened in 2003. But the sterling cup for excess goes to Syncrude's Stage 3 expansion, which was originally budgeted at C$4.1bn in 2001, and is expected to reach C$7.8bn before it is finished a year late, in 2006.

Needless to say, with so many fingers dipped in red ink, there is a lot of pointing going on. Petro-Canada, which has a 12% share in Syncrude, blamed rampant labour costs, renegade engineering firms and rambunctious weather for the overrun. Others blamed transportation bottlenecks and delays in the delivery of vital components.

Regardless of the causes, a crescendo of scale-backs and postponements has arisen. Petro-Canada announced that C$5.8bn worth of work on its in-situ Meadow Creek bitumen project would be curtailed, while CNRL said that it would spend a year rethinking its commitment to its C$8.5bn Horizon project.

Amid all the bluster and blather, however, some candour is beginning to emerge. While Suncor attributes much of the 75% increase in the cost of the Millennium expansion to boosting expected output and the addition of a hydro-treating facility, it admits that undue haste also had an impact. 'When we built it, we had a timetable to stick to, and we started while engineering was still underway,' says Brad Bellows.

With that candour, comes solutions. First and foremost, projects are being reduced in majesty. 'We are taking on projects in smaller, bite-sized components because it's easier to control budget and timeline,' comments Bellows. 'For instance, the first stage of Firebag, in which we added 35,0000 b/d of in-situ bitumen production, was budgeted at C$630mn. The second stage will essentially be a clone of the first stage, but cost only C$515mn.'

Secondly, rather than allowing giant engineering firms to ride unbridled over engineering, procurement and construction (EPC), ultimate decision-making and control have been reined back within corporate walls. 'Based on what we learned, we established an In-house Major Projects Group,' says Bellows. 'We have taken over engineering, procurement and construction.'

Finally, planning is being advanced as much as possible before the first shovel goes into the soil. 'With Firebag and Voyageur, we're looking at having most engineering complete beforehand,' notes Bellows.

Photo: Shell Canada

Froth treatment at the Muskeg River Mine removes fine clay and sand particles. The result is a very clean bitumen product which is transported to the Scotford Upgrader, near Fort Saskatchewan (see box piece).

Other factors are being rectified. One of the major contributors to the overruns was labour – at Syncrude's Stage 3, for instance, what was originally supposed to take 15mn hours to complete will now exceed 25mn. Part of the hourly escalation is due to the unwieldy nature of a large construction force. 'With Millennium, we had a steep ramp-up and ramp-down, with 6,000 workers on site,' explains Bellows. 'With Firebag, we'll keep more consistent, constant workforce of less than 1,000.'

Access is also being addressed. The oil sands region around Fort McMurray is geographically isolated, with only one major road into the area. 'Highway 63 comes right into town, so vessels currently pass straight through town,' says Bellows. 'The cokers for our Millennium project were huge. They had to go through all sorts of detours and byways to clear underpasses and bridges.' Recently, a working group was put together to study ways to improve transportation – as much as C$1.8bn could be spent to augment road and rail connections.

One of the least expensive innovations, however, may be the creation of a made-in-Alberta construction database. Initial cost projections were made based upon the experience of building large petroleum complexes in southern states such as Louisiana – as anyone who has ever spent January in Fort McMurray will attest, northern Alberta is hardly magnolia country. Industry leaders have called for the provincial government to establish local, more realistic engineering guidelines.

Foot off the gas

Although most of the cost overrun problems can be resolved in-house, one ailment that cannot be easily cured is the cost of energy – specifically, natural gas.

Coaxing bitumen out of the ground is notoriously energy-intensive. In mining operations, the thick, tarry substance must be separated from its sand matrix in giant washing machines filled with hot water. In-situ processes, such as SAGD, rely on the bitumen flowing to the surface through wells by heating up the reservoir to as much as 200°C with steam. According to the NEB, it takes approximately 250 cf of gas to mine the bitumen; in-situ production through steam injection requires 1,000 cf of gas, while upgrading to synthetic oil requires 300 to 700 cf (depending on how much gas is converted to hydrogen for processing).

None of that mattered when gas was cheap and abundant. Only four years ago, 1,000 cf of gas could be had for as little as $1. All that has changed, however. Statistics Canada reported that, in 2003, gas production fell 3.8%. Yet North American demand is growing at 1–2% a year, fuelled by a thirst for electricity from gas-fired turbines. As expected, the supply/demand crunch is causing prices to rise. So far, gas prices averaged $5.76/mn Btu for 1H2004. Cambridge Energy Research Associates (CERA), a consultancy, predicts that prices will remain on average above $6/mn Btu for the next three years.

Several energy-reducing techniques have been incorporated into the various processes, such as lowering the temperature of hot water in the separators. But energy input reductions cannot keep pace with expansion. The oil sands currently use around 0.6bn cf/d. If synthetic crude production reaches 2.2mn b/d, the region could consume as much as 2.5bn cf/d, placing significant demands on dwindling supplies.

Oil sands companies are well aware of the issue and are working on various ways to increase energy efficiency and reduce natural gas usage. Cogeneration (in which steam for SAGD projects is used to power the electricity-generating turbines) doubles the efficiency of natural gas consumed. Swapping to cheaper fuels is also an alternative. 'At Firebag, we have the option to build dual-burner-tip steam generators that run on gas or diesel, which we produce at the upgrader,' comments Bellows.

One project has come up with a plan to dispense with natural gas entirely. Long Lake is a C$3.4bn, in-situ project that is expected to produce 70,000 b/d of bitumen when it comes onstream in 2007. Its two partners, Nexen and OPTI Canada, are also building OrCrude, a proprietary upgrader that will produce 60,000 b/d of sweet premium crude. Alongside the upgrader, they are constructing a gasification facility that will produce its own fuel onsite from waste fractions of feedstock. 'OrCrude feeds liquid asphaltenes into the gassifier, which creates synthetic gas used to power steam injection,' explains OPTI Canada spokesman David Coll. 'The integrated approach on site is very efficient, it virtually eliminates natural gas. We save $5–$9/b on operating costs.'

Other technologies are being investigated, such as vapex, which uses vapourised butane and propane to loosen in-situ bitumen and coax it to the surface. Researchers have some very imaginative ideas, however, that lie even further beyond the horizon. Dr Steve Larter, a Professor of Geology from Newcastle, is fascinated by the action of microorganisms upon oil and gas deep within the Earth. One of his long-term research areas focuses on biological in-situ recovery – using bacteria to break down unwanted heavy oil fractions into valuable natural gas. 'Essentially, the microorganisms eat heavy oil and fart out methane. There's only a small amount of methane in a barrel of heavy oil, but there are a lot of barrels,' he says.

Professor Pedro Pereira-Almao, internationally recognised for his work in upgrading Venezuelan heavy oil with super-heated steam, is now busy at work with refinery catalysts at the University of Calgary's Institute for Sustainable Energy, Environment and Economy (ISEEE). 'What if you could make the catalysts really tiny, in the order of 100 nanometres?' he speculates. 'You could put the catalyst and hydrogen in the heavy oil and send it down a 300-km pipeline and the upgraded oil would come out at the other end! Is it possible, or not?'

Pivotal role

In spite of the obstacles, the continuing high price of oil and ever-increasing demand for energy guarantees that investment will continue to take place in the oil sands for the foreseeable future. 'The bottom line is that the oilsands will play a pivotal role in meeting Canada's and North America's oil-related energy needs in the next 25 years and beyond,' states CAPP's Devries. 'They're very active in investigating new ideas and technologies. Everything looks very positive.'

Oil sand is key to meeting North America's continued energy needs

Photo: Syncrude

Athabasca oil sands growth

Shell has outlined growth plans for the Athabasca Oil Sands Project (AOSP) in Canada that would increase bitumen production to between 270,000 and 290,000 b/d by 2010.

During the first year of operations for the AOSP, the focus was on improving reliability and ramping-up bitumen production to the design rate of 155,000 b/d – a goal now achieved. Over the next three years, a number of debottlenecking projects are proposed at the Muskeg River Mine and Scotford Upgrader to increase the bitumen production rate to between 180,000 and 200,000 b/d. Modifications are also proposed at the upgrader to enable the processing of the heaviest product stream into lighter, higher value crude blend components.

Over the 2006 to 2010 period, planned expansions of the Muskeg River Mine and Scotford Upgrader are expected to further increase bitumen throughputs by approximately 90,000 b/d, taking total expected AOSP production to between 270,000 and 290,000 b/d. Expansion of the Muskeg River Mine would include mining plans and additional mining equipment to recover resources from additional areas located on Lease 13 and from Lease 90, and an additional train for bitumen extraction and froth treatment processing. Expansion of the Scotford Upgrader would include the addition of a third hydro-conversion unit and associated utilities. The preliminary capital cost estimate for these expansion projects is in the range of $4bn.

Additional growth projects could follow over the longer term, including the mining of oil sands resources on the eastern part of Lease 13 and Leases 88/89 and on the recently acquired Leases 9 and 17 to increase total bitumen production to over 500,000 b/d. Planning is currently focused on ways to integrate the development of resources on the east side of Lease 13 (the Jackpine Mine development) with operations at the Muskeg River Mine. Upgrading options to process this additional bitumen production are also currently under review.

The AOSP consists of the Muskeg River Mine located north of Fort McMurray, Alberta and the Scotford Upgrader located near Edmonton and is a joint venture among Shell Canada (60%), Chevron Canada (20%) and Western Oil Sands (20%).

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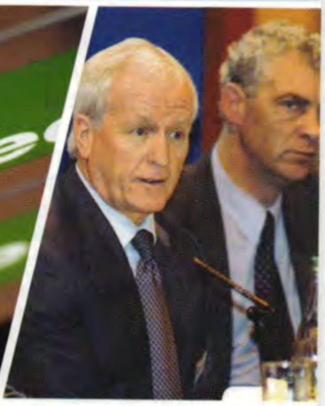

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Indonesia faces energy investment challenge

Indonesia faces a major challenge in the coming 18 months as the new government tries to raise badly needed finance to boost the country's under-funded energy sector. Starved of investment since the 1997 economic crisis, the energy sector runs the risk of heading into further trouble as output reduces from depleted oil and gas fields without new reserves coming onstream to replace lost production. *David Hayes* reports.

Indonesia's oil and gas industry came under the spotlight early this year following an increase in oil imports that relegated the country's status to that of a net oil importer – an unlikely situation for a member of Opec, of which Indonesia currently holds presidency. Indonesia's temporary relegation to that of a net oil importer has been caused by difficulties in attracting oil and gas investment as major producing fields decline while domestic energy demand grows.

According to Indonesia's Directorate of Oil and Gas, exports of crude oil were 470,000 b/d in 2003, while imports averaged 360,000 b/d. However, oil imports rose sharply early in 2004 to reach 13.5mn barrels (or 467,000 b/d) in February, while crude imports were 14.9mn barrels (515,000 b/d). In March crude imports reached a record 17.4mn barrels, almost 562,000 b/d, while exports were 14.3mn barrels (462,500 b/d). In both February and March Indonesia's total crude production averaged about 1.1mn b/d, some 13.4% below its current Opec quota of 1.22mn b/d.

Although the oil import situation soon corrected itself in the second quarter as Indonesia reverted to being a net oil exporter once again, the newspaper headlines that followed publication of official statistics confirming Indonesia's temporary loss of net oil exporter status caused more than a blow to the nation's pride.

Prompted by press reports to respond, Energy Minister and current President of Opec, Purnomo Yusgiantoro, expressed confidence that Indonesia's status as a net importer was just temporary and that the country would soon become a net exporter again. In addition, BP Migas, the oil and gas industry upstream regulatory body, revealed that the government had started urging oil companies to speed up production at new fields.

Raising oil production

Raising oil production may not be so easy, however, as energy analysts believe that Indonesia's ageing fields and the lack of investment in the oil and gas sector caused by taxation disincentives and bureaucratic problems will make this a tough target to achieve.

Oil is Indonesia's major source of primary energy. In 2002 total primary energy consumption is estimated to have reached 4.45 quadrillion Btu – equivalent to 1% of total world energy consumption. Oil accounted for an estimated 48.5% share of primary energy consumption, while natural gas was 29.2% and coal 16.1%.

According to the Centre for Petroleum and Energy Economics Studies in Jakarta, Indonesia will need to increase production by almost 20% to 1.3mn b/d by 2007 in order to keep pace with the growth in domestic oil demand if economic growth forecasts prove to be correct. Ramping up production to 1.3mn b/d will depend on the investment climate improving, luring foreign investors back to Indonesia. A speedy resolution is needed to various disputes holding back production increases, including the long running dispute between Indonesia's national oil and gas corporation, Pertamina, and ExxonMobil over the Cepu field in Java, which the two companies are jointly developing.

Estimated to hold reserves of at least 600mn barrels of oil, Cepu has the potential to reverse Indonesia's declining oil production once the new field comes onstream. However, the two partners have been unable to reach agreement over profit sharing, with Pertamina demanding half the field's output while ExxonMobil is demanding that Pertamina cover half the field's production costs. In addition, ExxonMobil wants the Indonesian government to extend its technical assistance contract, which is due to expire in 2010, for 20 years. According to recent reports, ExxonMobil officials have indicated that the field could produce up to 180,000 b/d and be operational in 2006 if the dispute is resolved shortly.

Smaller fields could also help raise oil production when they become fully operational. Unocal's West Seno field, under development offshore East Kalimatan, is producing 40,000 b/d and is expected to produce up to 60,000 b/d when the second development phase is completed in early 2005. Elsewhere, ExxonMobil's Banyu Urip field in Java is expected to come onstream in 2006 and reach its peak production capacity of 100,000 b/d soon after.

However, Indonesia's oil production is not likely to rise markedly due to the continuing decline of mature fields such as Caltex's Duri oil field in Sumatra. Caltex is the largest multinational oil company operating in Indonesia. In spite of the steam injection enhanced oil recovery project at Duri, production at the field fell by about 71,000 b/d in 2003. Half of the drop has been attributed to natural depletion.

Refinery plans

Indonesia also is due to increase its limited refining facilities, which have made it a net importer of petroleum products for some years. Indonesia's 10 refineries currently produce 70% of the country's petroleum product requirements, with the remaining 30% being supplied by imports. The largest refineries are the 348,000 b/d Cilicap refinery in Java, the 241,000 b/d Balikpapan refinery in Kalimantan and 125,000 b/d Balongan refinery.

At present Pertamina is in talks with Malaysia's Petronas and state-owned National Iranian Oil Company to build a $1bn, 200,000 b/d refinery at Tuban in East Java to reduce Indonesia's dependence on imports. Tuban is not the only new refinery project as additional refining capacity is due to be commissioned before Tuban is completed. A consortium of Indonesian, Chinese and Saudi Arabian companies is understood to be building two refineries that will process Saudi crude for the mainland market.

Challenges ahead

In fact, increasing investment in oil production is just one of many energy issues awaiting the new soon-to-be-appointed Indonesian government. At the time of writing, with two-thirds of the expected presidential election votes counted, challenger Susilo Bambang Yudhoyono was leading President Megawati Sukarnoputri by 60% to 40%

– a victory margin that was forecast to stand as the count was finalised as *Petroleum Review* went to press. As a former Energy Minister in Mrs Megawati's government, Yodhoyono already is familiar with many energy sector problems that need to be tackled if the economy is to sustain its growth path in future.

The challenges that Yudhoyono faces are enormous and it is uncertain how he will handle politically sensitive issues that Megawati has avoided – in particular his undertaking to phase out fuel subsidies which are forecast to amount to 2.3% of GDP in 2004 and will cancel out any windfall that Opec's only Asian member could have reaped from record oil prices this year.

'Now is the shorter, second presidential election round. For businessmen all has gone peacefully so far,' commented a diplomat in Jakarta. 'The macroeconomic picture has improved to the pre-1997 crisis situation but there are not the same growth levels. The economy was growing 7% to 8% annually before 1997 and it's about 4% this year. Financial reserves are growing steadily. The level of foreign investment in Indonesia has been falling in 2004 as it is election year. People wait to see what the political situation is. Most oil and gas blocks offered last year have gone to second tier players from South Korea, Malaysia and China. Chinese investment by Petrochina and CNOOC is starting to grow.'

Oil and gas

Indonesia has proven oil reserves estimated at 4.7bn barrels. In addition, estimated proven natural gas reserves total 90.3tn cf. At present Indonesia is the world's largest exporter of LNG, shipping the equivalent of 1.3tn cf in 2002.

The gas sector also faces problems with declining production, while plans to expand gas use for domestic consumption and leave more oil for export have been held up for more than a decade due to funding issues and bureaucratic problems. Bontang LNG liquefaction plant in East Kalimantan has become the main producer of LNG as the Arun plant in Aceh in North Sumatra is operating at only half its capacity, due to the depletion of gas reserves in fields supplying the Arun plant.

Interest in Indonesia is growing among smaller oil companies as large Asian oil and gas importing nations seek new supply sources. The earlier batch of exploration blocks tendered in 2003 attracted more interest than the 13 blocks offered previously in 2000. After tendering 15 oil and gas exploration blocks in 2003, the government is due to tender 27 blocks this year. Ten blocks have been tendered already and are expected to be awarded after the new government takes office. The 17 remaining blocks will be offered by the end of the year. Although fiscal and profit-sharing terms on the 10 blocks are not identical, all are intended to serve as incentives to investors.

'At the moment the main question for investors is incentives and the split of production sharing contracts. Some say the incentives here are not as good as neighbouring countries like Vietnam,' the diplomat said. 'Reports say BP, Shell and others are looking at downstream opportunities as Pertamina now has to compete. The landscape is changing, but slowly as people are waiting to see. China and more Asian players are expected to bid, but if attractive blocks are offered then you cannot rule out major players.'

Restructuring and deregulation

As part of efforts to attract foreign investment Indonesia has started to restructure and deregulate its oil and gas industry, although the exercise is still far from complete. In October 2001 the Indonesian legislature passed Oil and Gas Law 22/2001 that set limits on Pertamina's monopoly of upstream oil development from the end of 2003.

Changes in Indonesia's oil and gas laws resulted in Pertamina losing its regulatory and administrative functions and the establishment of BP Migas as the upstream regulatory body, while BPH Migas was created as the downstream regulatory body covering transmission, distribution and oil refining. However, reports from foreign companies suggest that BP Migas may even be less efficient than Pertamina before the regulatory restructuring was implemented.

Further changes are currently under way. In July 2004 Pertamina lost its retail and distribution monopoly on petroleum products. BP and Petronas of Malaysia are expected to receive the first licences for foreign companies to retail petroleum products. The government has promised to open the petroleum product sector to full competition by 2005, although progress has been slow so far.

Meanwhile, with oil production under pressure, Indonesia is looking to accelerate development of its huge natural gas resources. About 75% of all gas reserves are in Sumatra and offshore in the Natuna Sea, where they lie between Peninsular Malaysia and Kalimantan. Although Indonesia produces about 2.9tn cf of gas annually, about 75% is exported as LNG. Japan takes about 70% of LNG exports and South Korea around 20%, while Taiwan imports most of the remaining LNG production volume. In addition, piped gas is exported to Singapore and Malaysia from the offshore West Natuna field in the South China Sea and to Singapore from the Grissik gas field in Sumatra.

Meanwhile, Indonesia is planning to build several major gas pipeline schemes to transport gas from South Sumatra and East Kalimantan to the island of Java, which is the country's economic centre and largest consumer of energy. The pipelines are intended to meet the current gas shortage on Java where plans to build a trans-island gas grid have been held up by the 1997 financial crisis and subsequent economic and political problems. Piped gas distribution remains largely undeveloped due to a lack of investment and has resulted in oil consumption growing while huge gas reserves lie untapped.

Indonesia also plans to develop more remote gas reserves to export as LNG, while both LNG and CNG are planned to be used to increase energy supplies to Java and the scattered islands throughout eastern Indonesia. BP already has agreements to export LNG from its Tangguh LNG liquefaction plant under construction in Irian Jaya to Fujian Province in China, Posco and the SK Group in South Korea, and Sempra Energy of the US. BP also is talking with other potential customers including a deal to supply Jiangsu Province in East China.

Other gas development prospects include the Donggi gas field offshore west central Sulawesi. The Badak gas field, lying in deep water off southern Timor, is another candidate but more difficult to develop because of the greater depth. Both Donggi and Badak are mooted for LNG development.

In addition to its large oil and gas resources, Indonesia is Southeast Asia's largest coal producer, consumer and exporter. Coal production is thought to have risen around 3% in 2003 to reach about 105mn tonnes compared with 102.9mnn tonnes in 2002. Production rose due mainly to an increase in exports after three new coal supply contracts were signed with Taipower of Taiwan.

In 2003 Indonesia exported an estimated 75mn tonnes, up 3.6% compared with 72.4mn tonnes the previous year. Indonesian coal exports have risen by 25% over the past three years due to increased coal purchases by other Asian countries. Domestic coal consumption continues to rise and is thought to have reached almost 30mn tonnes in 2003, up about 3% compared with 29mn tonnes in 2002. Power stations are the largest coal consumers in Indonesia, burning about 19mn tonnes annually, equivalent to about 65% of total domestic coal demand. The Ministry of Energy has forecast that Indonesia's domestic coal demand will increase by about 1mn t/y, to reach 35mn tonnes in 2007 as more coal-fired power plants are built.

The lubes business from the sidelines?

Sebastian Crawshaw, CEO of OATS,* provides a personal overview of the continually evolving European lubricants market, looking at what changes businesses are having to implement in order to survive.

Successful organisms evolve. Those that do not, eventually disappear. The lubricants business is no different – it is evolving and, in order to survive, each organisation, at whatever level, needs to adapt its offering to better suit its particular competitive position.

Several key trends have been emerging as a result:

- Shift from national to regional and global organisations.
- Continuous cost pressures.
- Product range rationalisation.
- Line of business management, focusing on specific segments.
- Increasing importance of distributors.
- A move to the east of Europe.
- Specification driven partnerships.
- Increasing use of electronic media.

In 1997 BP entered into a lubes joint venture with Mobil that marked the beginning of a major consolidation in the lubricants sector. Dr Manfred Fuchs in his address to ILMA (Independent Lubricant Manufacturers Association) in 2002 listed over 25 acquisitions mergers and demergers. More have taken place since and, today, the 'Seven Sisters' have shrunk to the 'Big 5' – ExxonMobil, BPCastrol, Shell, ChevronTexaco and Total.

This has created a new attitude to the relatively stable world of lubricants marketing. Multi-brand strategies common in other industries had to be adopted, while some brands completely disappeared and others became relegated to niche markets. Combined with the changes in the geo-political scene in what is now referred to as Central Europe, the European arena is now hugely different post-1997.

The legacy of the mergers was to create a review of the organisational structures and the way in which these businesses were managed. The national identity of the major organisations that was so important in the 1970s became greatly de-emphasised. The majors' head offices were sold off and downsized in countries such as France and Germany and, today, organisations are now being run on a pan-European basis.

Initially this took the form of European head offices. However, centralising staff brought operational costs, as building European teams composed of the 'right cross-cultural blends' resulted in co-locations of people. This may have helped to give a pan-European feel, but it came at considerable expense – especially as many had to travel to the local market implementers. In a market declining at 5–10% per annum, this situation could not last.

Cost reductions resulted – companies cut headcount and returned hardworking staff to their original countries. Many were relocated to work from home, with Internet and Broadband connection permitting them access to the normal office functions. Travel, however, has not diminished and continues to be the bane of all of our lives – especially those tasked with pan-European or cross-regional responsibility.

Post-merger, virtually every organisation had duplicate products, different brand names, confused market positioning and too many sales people. Product range rationalisation was thus the next rational next step. Many refineries closed as part of the cost reduction process, with products resourced from sometimes just a single large refinery, while product lines were slashed – sometimes from as many as 5,000 lines to around 1,500.

However, as so often, there is a conflict between the centre and the periphery. At the refinery and the regional management level, there is a drive to reduce the number of products. While there are indeed advantages of homogenous marketing programmes – they save time and achieve standardisation of brand image – there are very often genuine local needs that need to be met.

For example, Nordic countries are colder than Mediterranean ones! The same applies between Canada and Florida. This will not change, even with global warming! Lower viscosities are needed in colder climes and synthetics are more readily adopted and can exceed 50% in some sectors. By contrast, in Turkey and Greece – where the temperatures are higher and the car parc relatively older – large quantities of mineral oil based 20W-50 are still sold.

This is not rocket science. But it has serious implications for the executive trying to promote lubricants on a pan-European basis.

Sales strategies have been evolving too. It is no longer good enough just to supply the oil. Every company in a declining market is looking to add value to their offering. This means adding in services that previously were complex or expensive to provide, such as lubrication surveys for fleet operators. Used oil analysis and performance tracking has also become more important.

This is no longer a differentiator, today it is a basic requirement.

To reduce the cost of sales many companies are now focusing on distributors – shifting the cost of stocking, warehousing and support to another part of the distribution chain. In some cases volume contracts have been offered to the distributors, along with privileged access to Internet purchasing solutions that allow them to order directly from the supplying lubricants company.

Meanwhile, technical teams have been decimated as part of the merger and cost reduction process. Previously, each large European country would have its own chief engineer and a team of technical specialists who would answer questions and liaise with local OEMs (original equipment manufacturers). However, since many of the calls for technical and marketing support come from distributors, information tools that enable them to answer questions themselves are now becoming a priority, both to improve service and to reduce costs.

With the decline in sales volumes in Western Europe (as drain intervals are extended) and the growth in the Central European states, it becomes sensible to relocate facilities to Central Europe. Support operations, both technical and back office, are being moved to the new members of the European Union (EU), with huge savings in employment costs.

In these countries there is a different game being played from the mature Western European model. For the efficient majors, taking market share of the recently de-nationalised enterprises is comparatively easy.

Cars are a major financial asset in Poland and other Central European countries and the workshops market has become a major battleground. To win market share, the oil companies have to invest in the workshop infrastructure, which will, in turn, be tied to the lubricant supply for several years. Effectively it is an investment battle to build market share while they are still fluid.

It is worth commenting that these investments, together with the training that supports them, is providing invaluable stimulus to these formerly communist territories. New entrepreneurs are being trained in how to operate a franchised business and this, in turn, will foster greater enterprise. Often the world major oil companies are criticised for exploitation. In this case they are to be commended for being engines of enterprise and creators of beneficial social change.

The API CD standard was introduced in 1955 and it was 32 years before API CE was introduced. Nowadays, however, standards are changing far quicker.

In the 12 years between 1990 to 2002 four new API standards were introduced, driven by legislation related to emissions reduction. Indeed, environmental pressures are placing ever-increasing strain on the formulators and oil companies who are required to keep their products up to date. The marketing and research costs (engine tests etc) are inevitably increasing, yet the time to recover these is decreasing.

Despite the continual change in specifications it is noticeable that the source information received by OATS, usually in the form of copies from manuals, does not always reflect the current standards. It is not unusual in the construction equipment sector, for example, to see API CD still being recommended for engines.

So, there is a need for the developers and marketers to make a more concerted effort to ensure that all documentation, both internal and external, reflects the current standards. Indeed, this is a topic currently being debated by ACEA and the European lubricants industry at large.

A decade ago there were around 300 specifications used regularly (and referenced in the OATS database). Today there are more than 3,000 codes and the process of selecting the right standard, for the right lube for the right job is becoming much more complex. Major oil companies have their favoured relationship with their key supplier and increasingly are using part numbers that can make the underlying specification difficult to establish. The oil change intervals are no longer a simple variable depending on the hours used or the distrance travelled. More and more truck manufacturers are making recommendations based on usage patterns, operating conditions, the type of lubricant used and the fuel (when they are not relying on automated monitoring systems).

In today's market, all of the major oil companies have products that could meet the manufacturer's needs – even if they do not have a full approval. Each oil company, not surprisingly, is trying to protect its preferred relationships. However, for its distributors and sales staff, the key is providing the information that will allow them to compete.

With the advent of the GF4 standard, the US market is catching up with Europe. Until now the US has primarily had backwards-compatible recommendations for lubricants. GF 4 will change that and we expect to see the emergence of a more complex position in the US and associated markets.

My observations would not be complete without at least a passing reference to China. The country is seeing unprecedented rates of economic growth, which is absorbing a wide range of materials.

Trying to create low cost (compared with Europe) and robust solutions that will work in the local market is the key challenge facing lubricant marketers. This is a marked contrast to the European situation, where increasing the quality and the cost is seen as a crucial strategy.

Whatever the future – and none of us has a perfect crystal ball – it will be the most adaptive businesses that will prosper.

OATS publishes 'EARL5', a leading lubricants recommendations database for the oil industry. Visit* ***www.oats.co.uk* *for more information, or e:* ***bulletin@oats.co.uk***

Supplying lubes data

OATS celebrated its 20th anniversary earlier this year. Today it employs 20 people, while turning over £2.5mn/y. The company was initially set up by Brian Harris, after a 30-year stint at Esso, and Mike Dixon. In 1984, the OATS product was a simple paper print-out, developed by Harris, previously a principal scientist at the Esso Research Centre. He realised that it was becoming increasingly difficult for oil companies to afford their own in-house data collection and information services, and formed OATs to do the job for them.

After 10 years the owners of OATS and their wives wished to retire and sell up the business. At this point the current Managing Director – Sebastian Crawshaw – bought into the company. He told *Petroleum Review* that the immediate challenge was to convert the product to being computer-based.

He explained that like all such conversions there had been considerable challenges in the changeover, but once it was achieved it became easier to extend both the range of vehicles and equipment covered, and to extend the geographical scope of the product. 'Going abroad was the key,' he explained, noting that by the 1990s the largest oil companies were increasingly moving from a national focus to regional focus. According to Crawshaw, the move to becoming fully European increased the competition but also really opened up the potential.

The latest company product – Earl 5 – contains 66,000 records on 28,000 pieces of equipment from around 1,600 manufacturers. Delivery is now available on CD-Rom or online. The data comes under five broad headings:

- Retail – covering cars, vans, pick-ups, SUVs and motorcycles
- Commercial – heavy commercial vehicles and buses
- Agricultural – all farm and parks/playing field equipment
- Off-highway – mobile and static construction equipment
- Industrial – engineering and industrial machinery

Crawshaw explained that as the OATS product is used by the oil companies in a variety of selling and planning situations, the key to the company's success has been in demonstrating the accuracy and reliability of the product to the users. Virtually all the modules are now available in 15 European languages. The reliability of the product is achieved by taking the data from the original equipment manufacturers (OEMs), and then getting the OEMs to sign off that the data has been correctly captured and presented. The next step is to customise the data by company.

According to Crawshaw, the increasing move by companies to offer premium and standard lubricants solutions has led to increased usage and interest as sales staff can reliably offer customers the recommended options.

The individual companies working with OATS receive the data on CDs, via the web or as printed guides depending on requirements. Updates are issued quarterly, although the move to web-based data supply means as soon as new data is validated it will be available.

Crawshaw's view was that it was only by constant innovation that you could stay competitive and meet customer requirements. He explained that the company was looking at adding more languages and at offering ever more innovative packages to analyse and present data for use by its customers.

In terms of regional spread, Crawshaw noted that the increasing range and sophistication of the lubes required in the US market made it an interesting market opportunity and one he hoped OATS would be tackling in the near future.

Healthy global resource base as production rises

IHS Energy has just released its latest _World Petroleum Trends_ (_WPT_) report, which highlights petroleum trends between 1994 and 2003. The study indicates that worldwide oil and gas production has increased during this period, to give a healthy remaining global resource base.

Based on IHS Energy's comprehensive global data, which is derived at the field level from governments, operators and reporting agencies, the report draws what Rob Mobed, President and COO, called 'some unique and significant conclusions'. In terms of long-term remaining resources in the ground, the study indicates that the global resource base for hydrocarbons is still healthy and will be aided by a growth in exploration investment that is currently underway. This is despite the fact that an energy 'demand crunch' does exist at the moment, and that certain factors – particularly of a geopolitical nature rather than geological – have led to oil prices above $50/b in recent weeks.

Long-term, the analysis provides a more positive outlook than the current price environment suggests, for several reasons, which can be summarised as follows:

- Oil reached a new peak in production during 2003, while gas pushed past the 100tn cf level for the first time ever. Also, there are a number of major projects still due to come onstream, suggesting no obvious shortfalls in oil production in the short-term to 2008.
- In terms of total global resource discoveries, 2003 appears to have been better than 2002. A total of 46 major discoveries (100mn boe or greater) were made worldwide during 2003, an increase of five over 2002.
- Over the period 1995–2003, total resource additions resulting from resource growth in pre-1995 discoveries plus 144bn barrels of resource additions from new field/new pool discoveries significantly exceeded global liquids production during the same period.
- Major discoveries are widely distributed geographically – 51 countries contributed one or more discoveries of 100mn boe or greater during the decade 1994–2003.
- A focus on coal-bed methane, heavy oil and natural gas liquids is adding to the growth in reserves supply.
- International exploration success declined from the record high of 45% successful wildcats in 2002, disrupting the upward trend in success rates seen over the decade. However, this success factor will no doubt increase as discoveries are gradually reported from wells currently classed as 'tight'. The North American new-field wildcat (NFW) success rate reached a record high of 45% in 2003, significantly higher than the previous peak of 39% in 2001 – partly aided by coal-bed methane drilling.
- Deepwater played an increasingly dominant role in the past decade – with a record 70% of all discoveries in 2003 being made in water depths of over 200 metres and 65% of all discoveries occurring in water depths greater than 1,000 metres. Significant investments in deepwater exploration and production technologies have been developed by major international operators over the decade fuelled growth in reserves and production which were inaccessible and uneconomic at the beginning of the period.

'We believe we will now see an upturn in strategic exploration investment and the report identifies a time-lagged correlation between higher oil prices and exploration activity. Overall expenditure increased significantly during the decade, despite a decline in exploration spending by the majors. The historical shift in increased expenditure was towards production, especially in deepwater, heavy oil and unconventionals. The highlight during the period included the role of international national oil companys (NOCs) and smaller independents in taking-up the exploration challenge,' said Mobed.

Remaining resources

Total worldwide liquids resources discovered through end-2003 amounted to 2,285bn barrels, with cumulative production of 1,020bn barrels. The remaining resources of 1,265bn barrels imply global liquids depletion of 44.6% at end-2003.

Worldwide gas resources discovered through end-2003 amounted to 9,725tn cf. By end-2003 some 2,910tn cf of natural gas had been produced – just below 30% of the initial resource. Stated more simply, the IHS Energy data indicate that global consumers have used about 45% of the oil and approximately 30% of the gas that was found worldwide before the end of 2003. Future discoveries that have not yet been accounted for are likely to come as a result of continuing innovations in technology and access to areas where challenging conditions exist, including areas that are presently inaccessible due to political circumstances.

Overall production levels

World liquids production (including condensate, natural gas liquids, oil sands and Orimulsion production, but excluding processing gains from refineries) reached another peak in 2003. According to IHS Energy's estimates, daily liquids production in 2003 averaged 75.5mn barrels, an increase of 3.2% from 2002 and 1.4% higher than the previous peak in 2001.

As **Figure 1** indicates, non-Opec liquids production reached a new peak at 45.7mn b/d, an increase of 1.9% over 2002. Opec country production accounted for 39.5% of the global liquids total, higher than the 38.8% achieved in 2002. Nevertheless, the 2003 Opec share was lower than the period 1993 to 2001 (throughout which Opec share exceeded 40%) and remains well below the Opec countries' production share in the 1970s when they regularly produced more than 50% of the world's liquids. At 29.9mn b/d of all liquids, Opec country production was still well short of the record production of 31mn b/d achieved in 2000.

Compared with 2002, the most dramatic regional increase in liquids production has come from the Former Soviet Union (+13.0%) on the back of a 14.6% increase in Russian production. Production from Saharan Africa rose by 8%, largely as a result of increased Opec production. Middle East production growth of 7.7% is also attributable to Opec increases. The increase might have been greater but for cutbacks in production in Iraq following the second Gulf war. Production from North America rose slightly, natural field declines being offset by a 140,000 b/d increase in production from Canadian oil sands.

Non-conventional liquids production from Canadian oil sands and Venezuela's Orinoco is estimated to have grown by 11% in 2003 to 1.28mn b/d, representing 1.7% of world production.

By contrast, four regions produced less in 2003 than in 2002. Although production declined in both Argentina and Colombia, the major decrease in Latin America came from Venezuela as a result of political unrest.

In 2003, natural gas production exceeded 100tn cf for the first time. Global gas production showed an increase of 3.4% above 2002. Gas production grew in all regions except North America, which saw a minor decline of less than 0.2%, a slight increase in US production being insufficient to offset the decline in production from Canada.

The greatest regional increase (23%) came from Sub-Saharan Africa where Nigerian production was boosted by full-year production from Nigeria LNG Train 3, which had come online in November 2002. Similarly, in Latin America, the 6% increase in production was largely attributable to the first full year of production from Trinidad's Atlantic LNG Train 2 and the start-up of Train 3 in April 2003.

Increased production from Qatar and Saudi Arabia contributed significantly to a 13.8% increase in natural gas production from the Middle East.

Ken Chew, Vice President of Industry Performance and Strategy, IHS Energy, said: 'Looking out over the longer term, production from the Former Soviet Union has been relatively stable over the past decade, but it is likely to rise as new pipelines are constructed in the Caspian region and the LNG schemes for the Sakhalin area, and possibly the Arctic, are developed. North American production peaked in 2001, and the declining trend may well continue unless Arctic gas from both Alaska and Canada can be brought to market. In Europe, the UK – the world's fourth-largest gas producer – has entered a gas production decline in 2003, but this will likely be offset by increased production from Norway's Ormen Lange super-giant gas field and Snøhvit LNG development by 2007–2008.'

Major discoveries

In terms of resource discoveries, 2003 appears to have been a better year than its immediate predecessor. A total of 46 major discoveries (100mn boe or greater) were made during the year, five more than in 2002. The largest discovery, Iran's giant Lavan gas-condensate find, was made in a Palaeozoic reservoir beneath Lavan (Sheykh Sho'eyb) Island. Lavan recoverable gas resources are estimated at more than 6tn cf.

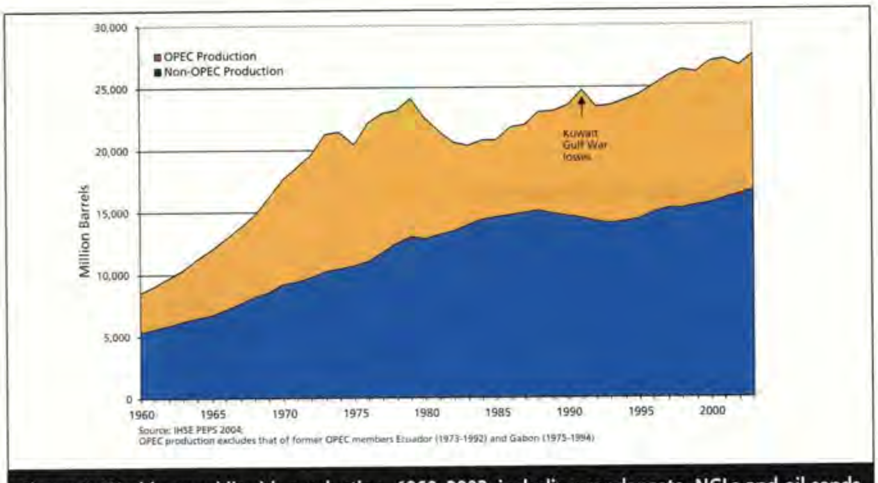

Figure 1: World annual liquids production, 1960–2003, including condensate, NGLs and oil sands

Although Lavan was the only billion boe discovery made in 2003, eight other giant discoveries in excess of 500mn boe were made – three in Brazil and one each in Angola, China, Malaysia, Sudan and Vietnam. The Chinese and Vietnamese discoveries were of gas-condensate and the remaining six were oil-dominant.

In all, the 46 major discoveries accounted for more than 9.5bn barrels of liquids and almost 24tn cf of gas. This exceeds the 2002 total from major discoveries by some 2bn boe.

Perhaps the most notable feature of the major 2003 discoveries was the dominance of deepwater success, with a record 70% of all major discoveries being made in water depths of greater than 200 metres and 65% in water depths greater than 1,000 metres.

This was also reflected in the distribution of resources, with 64% of all resources being located in deepwater – the first time deepwater has accounted for more than 60% of the resources of 100mn+ boe finds (**Figure 2**).

Geographic distribution

The major discoveries of the past decade have a wide geographic distribution. A total of 51 countries contributed one or more discoveries of 100mn boe or greater, with 13 countries accounting for gross resources in excess of 5bn boe.

Liquid resources of greater than 5bn barrels each were found in seven countries – Angola, Kazakhstan, Iran, Brazil, Nigeria, US and Saudi Arabia (in descending order of volume discovered).

Natural gas resources of over 5bn boe each were found in seven countries – China, Iran, Australia, Indonesia, Norway, Bolivia and Egypt (in descending order of gas volume discovered). Only in Iran were resource additions in excess of 5bn boe made for both liquids and gas.

Liquid new-field resource additions of some 13.9bn barrels were the fifth highest of the past decade, but only replaced 50% of production. Only three non-Opec countries – Kazakhstan, Angola and Brazil – have replaced their liquids production by new resource discoveries over the past five- and 10-year periods (see **Table 1**), although Malaysia has replaced its production over the past five-year period.

Natural gas resource additions of 68tn

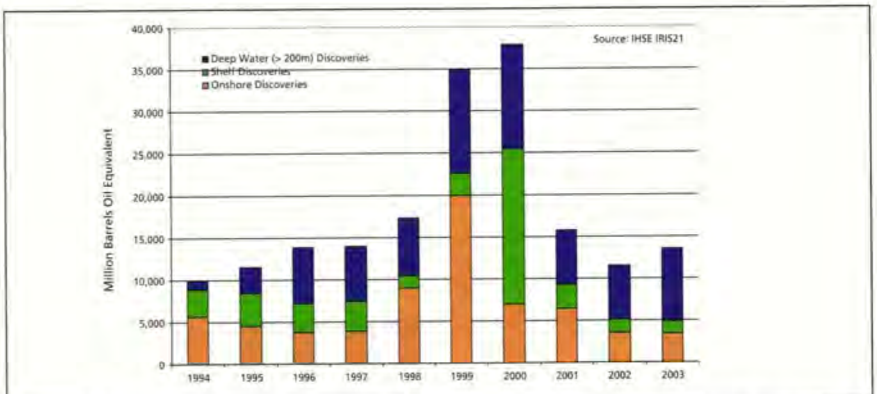

Figure 2: Resources of 100mn+ boe discoveries from 1994–2003 by physiographic location

cf were marginally greater than in 2002, but replaced only 67% of gas production. For the past three years discovered gas resources have failed to replace natural gas production.

Exploration performance

There has been a decline in nternational exploration success from the record high of 45% successful wildcats in 2002, but will doubtless increase as discoveries are gradually reported from wells currently classed as 'tight'. The North American new-field wildcat success rate reached a record high of 45% in 2003, significantly higher than the previous peak of 39% in 2001.

In 2003, 1,130 NFW wells were completed internationally, a 10% increase on the depressed level of 2002 and slightly above the average for the period 1994–2003. North American new-field wildcat drilling increased by 6% to 1,584 wells, but remained 8% below the average for the decade.

Analysis of company drilling activity indicates that NFW drilling by the large international players, in particular those major companies that participated in mergers in the period 1999 to 2000, has declined significantly from the year 2000 onward. The relatively flat level of total international NFW drilling during the past four years indicates that smaller companies have occupied some of this exploration niche.

The decline in international wildcat exploration by the large, internationally-active companies reflects a consistent trend during the past six years for these companies to spend a decreasing amount of their exploration and development budgets on exploration and also to spend a higher proportion of those exploration budgets in North America.

Liquids production rank	Country	Percentage liquids production replacement 1999–2003	1994–2003
1	Russia	12%	11%
2	Mexico	5%	10%
3	China	68%	64%
4	Norway	20%	28%
5	United Kingdom	18%	19%
6	Brazil	307%	288%
7	Kazakhstan	683%	441%
8	Angola	433%	450%
9	Oman	34%	27%
10	India	37%	23%
11	Argentina	19%	24%
12	Malaysia	121%	71%
13	Vietnam	99%	131%
14	Egypt	36%	35%
15	Australia	8%	6%
16	Colombia	92%	72%
17	Syria	17%	22%
18	Yemen	24%	21%
19	Ecuador	22%	30%
20	Denmark	91%	65%

Table 1: Top20 non-Opec liquids producers (excl. US and Canada) in 2003 and liquids production replacement from new-field wildcat discoveries in 1994–2003

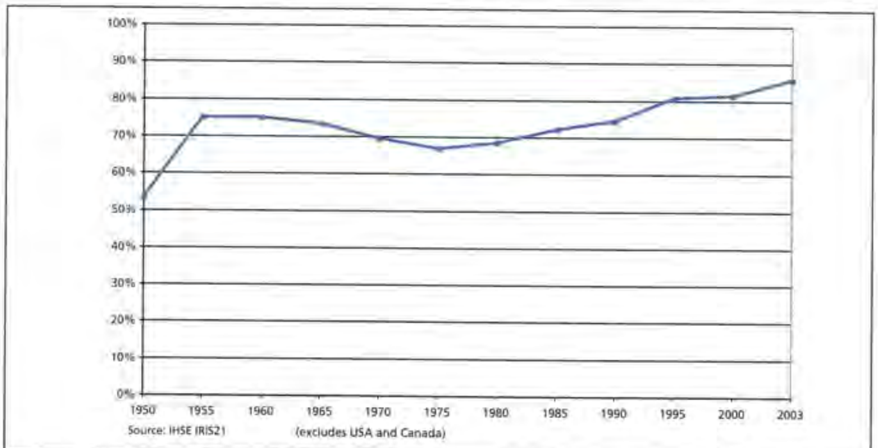

Figure 3: Percentage of total disc. resources onstream at end period (excl. US and Canada)

A question

Having read the above, readers of *Petroleum Review* may well ask: 'How has oil production continued to climb despite a reduction in exploration spending and fewer discoveries?'

There is a clear reason why oil production has not yet peaked and global depletion has not yet kicked in. Up to the end of the 1970s (with the exception of the post-war boom in the early 1950s), the industry discovered more resources than it brought onstream. Not only did the industry discover more but, up to and including the early 1970s, it tended to discover substantially more than the cumulative resources of the fields that were brought into production during each period.

In other words, the gap between discovered resources and developed resources widened in absolute terms, reaching a peak of 860bn boe of undeveloped resources by 1980. As **Figure 3** shows, between 1950 and 1975 it also widened in percentage terms.

In addition to the existence of this gap between discovered resources and developed resources, the climb in production can be explained by other sources of production including:

- the development of previous discoveries that are now available due to political change or political opening (e.g. the Caspian region);
- unconventional heavy oil projects (in Canada and Venezuela;) and
- gas-related liquids (condensates and NGLs).

Exploration – changing expenditure trends

While total expenditure increased during the decade, exploration expenditure as a proportion of total exploration and development expenditure (excluding property acquisitions) has decreased from 26.8% of all E&D expenditure in 1998 to only 18.7% in 2003. Secondly, the proportion of exploration expenditure incurred outside North America has also dropped, from 66% in 1998 to 58.5% in 2003.

However, the report does identify a link between higher oil prices and increased exploration activity with a time delay of 12 months. Therefore, we should be entering a period where companies are revisiting their strategic exploration investments.

The WPT *report is available through a subscription to IHS Energy's Petroleum Economics and Policy Solutions (PEPS) online service. It is also available separately for purchase. For more information, please e:* **sales@ihsenergy.com**

The Energy Institute has forged a new publishing agreement with Shell in a bid to help the oil and gas industry further improve its HSE performance. The initiative will allow, for the first time, Shell's Hearts and Minds Toolkit to be made available to companies outside the Shell Group.

Managing Health, Safety and Environment (HSE) is one of the major challenges facing any successful organisation. Large companies have been known to invest millions in management training programmes run by external consultants, designed to help them improve the HSE performance of their staff.

Yet it has been widely accepted for a long time that the most effective way of achieving world-class HSE performance is by engaging and empowering everyone in the organisation, from top to bottom. Shell is one of the greatest advocates of this proactive approach, which it calls 'Winning Hearts and Minds', and a recognised industry leader in the field.

The Hearts and Minds HSE programme was developed by Shell Exploration and Production in 2002 and has been successfully applied in Shell companies around the world. The programme uses a range of tools and techniques to help the organisation involve all staff in managing HSE as an integral part of their business. Collectively, these tools and techniques are known as the 'Hearts and Minds Toolkit'. For the first time, this state of the art Toolkit is being made available to those outside the Shell Group, thanks to the publishing agreement between the Energy Institute and Shell E&P.

Shell's Global HSE Security and Sustainable Development Manager, Volkert Zijlker, told *Petroleum Review*: 'The Hearts and Minds Toolkit is invaluable to Shell's management of world-class HSE. There is no competition in safety and by forging this partnership with the Energy Institute we want to continue to play a leading role in promoting best practice so that others can benefit from this work.'

Lawrence Slade, the Energy Institute's Business Development and Technical Director, said: 'The EI is delighted to be working with Shell to bring their highly-regarded Hearts and Minds Toolkit to the widest possible international audience.'

It is envisaged that adopting the Hearts and Minds approach will enable companies to reap benefits beyond improved HSE performance. Workloads should decrease as the organisation becomes more proactive. A culture of trust and shared information allows people to work without requiring extra supervision and control. Audits require less time to complete. Ultimately, people work safely and efficiently because they are motivated to do so – not simply because they have been told to do so. These same people want to actively participate in improvement strategies, and to take personal responsibility for their performance.

Tim Popp, Operations Management System Consultant Engineer at Unocal, explained why his company is taking this opportunity to invest in the initiative: 'What really attracts me to "Hearts and Minds" is that it's simple, user-friendly and looks like it'll be fun to use.'

To learn more, visit the 'Hearts and Minds' section of the Energy Institute's website at **www.energyinst.org.uk/heartsandminds** where the 'Winning Hearts and Minds Road Map' can be downloaded free of charge.

The Hearts and Minds Toolkit is available for purchase as a complete pack in a heavy-duty plastic wallet, or as individual brochures. Orders can be placed by using the online 'Request Form' found at **www.energyinst.org.uk/heartsandminds**

For more information, please contact the Publications Department at the Energy Institute:

The Hearts and Minds Toolkit is suitable for managers and team leaders at all levels, and is designed to be used without the need for costly consultants. The Toolkit addresses topics such as:

- *Understanding your culture* – An engagement tool to identify local strengths and weaknesses and find out how to build a stronger HSE culture.
- *Managing rule breaking* – To prevent incidents being caused by rule breaking.
- *Risk assessment matrix* – Helps people understand risks and stimulates action to address them.
- *Making change last* – A general tool for managing change and supporting any improvement process or organisational change programmes.
- *Improving supervision* – To improve the non-technical skills of supervisors.
- *Achieving situation awareness* – Helps people to make better risk-based decisions, and to be able to justify them.
- *Working safely* – Intervention programme that builds on and supports existing programmes or can be run by itself.

A region of opportunity

The Asia-Pacific region is one of the most dynamic and exciting areas for UK companies looking to increase their international business, writes *Ian Laing* of Advisors Asia Pacific.

A recently published report by the Asia Development Bank (ADB) revealed that the various national economies of the region have outperformed earlier estimates, with growth underpinned by sharply recovering exports and strengthening recovery among the major industrial countries. Intra-regional trade also remains buoyant, contributing to the overall positive feel in the area.

In its *Asia Development Outlook 2004* study, published on 22 September, the ADB revised its projection of 2004 GDP in the region upwards from the 6.8% it forecast in April to 7%. Even next year, despite a predicted levelling off of expansion in major industrial countries and a slowdown in China, growth will still be 6.2%, only marginally lower than the 6.7% forecast by the ADB in April.

Across most countries of the region, says the ADB, growth is broad-based, encompassing both a fast-expanding external sector and robust growth in domestic demand. This trend is also seeing a welcome return to investment following the Asian financial crisis of 1997/1998.

Growth is fastest in China, Hong Kong, Taiwan, Malaysia, the Philippines and in Singapore, while Indonesia, Cambodia and South Korea are growing less fast, but still at a respectable rate, the ADB said. Encouragingly, high growth rates are not being matched by inflation, which has so far remained relatively subdued across the region.

One factor underpinning this positive performance is, of course, the high price of oil internationally. While high oil prices could dampen growth slightly for markets such as China (which overtook Japan as the world's second-largest petroleum consumer last year), for the oil-producing countries of the Asia-Pacific region as a whole it could boost investment and open up considerable opportunities for UK and European-based companies to sell goods and services into this burgeoning marketplace.

New opportunities

A few years ago UKCS technology and services were not received with open arms in the Asia-Pacific oil and gas industry. There was an impression that foreign companies were trying to sell 'over-engineered' solutions and products to a mature market that had developed its own indigenous capability to meet local requirements. Foreign products, and particularly services, were often seen as too expensive and not appropriate.

However, that position has been transformed almost overnight as new reserves have been discovered in locations that demand exactly the kind of solutions developed in the more demanding environments familiar to operators in the North Sea.

It was at the end of 2002 that Murphy Oil announced a significant oil discovery in the Kikeh deepwater field off the coast of Sabah. Estimates put recoverable reserves at approximately 700mn barrels – the first major deepwater oil discovery in the region. If more recent estimates of recoverable reserves are correct, the Kikeh field alone will increase Malaysia's total crude oil reserves by as much as 15%. Encouraged by the Kikeh find, exploration of deepwater blocks around Malaysia has boomed over the last 18 months or so.

The latest discoveries put total deepwater and ultra-deepwater reserves in the area at around 900–1,200mn barrels of oil and 5.7tn cf of gas. Similar finds are taking place all the time, promising something of a boom in offshore exploration and production in the Asia-Pacific region over the next few years.

In turn, this opens up huge opportunities for UKCS companies, as the Asia-Pacific oil and gas industry moves into steadily harsher environments, deeper waters and more complex reservoirs in order to maintain and boost production levels and meet an increasing consumer demand, both at home and internationally.

Murphy Oil announced in August that it had received approval from Malaysia's Petronas for the Kikeh area field development plan. This envisages first oil from the field coming ashore in 2007, rising to production of 120,000 b/d within two years. In total, Murphy Oil expects to commit capital expenditure of around $1.4bn to this one development alone.

UK business role

Kikeh represents a distinct trend in the Asia-Pacific away from what were straightforward exploration and production activities to more technically and commercially challenging areas. This trend offers UK companies tremendous opportunities to exploit the technologies, services and processes developed in the UKCS.

The 'technology gap' between the UKCS and certain oil and gas markets in the Asia-Pacific region – such as Malaysia, Indonesia and Thailand – is narrowing rapidly. Technology and know-how offered by specialist companies from outside the region are just as rapidly becoming appropriate and increasingly more competitive. Expertise in almost every facet of offshore exploration and production is increasingly in demand in the Asia-Pacific region, but there are particular areas where UK companies could score heavily.

Deepwater expertise is top of this list, unsurprisingly given the trends outlined above. Also in growing demand is knowledge of marginal and small field development – operations which are becoming just as economically attractive as elsewhere in the world thanks to historically high world oil prices. Enhanced oil recovery technologies and know-how will also find ready markets in the Asia-Pacific province, as will decommissioning expertise.

To take just one example of a UK company opening up new markets in the area, the Aberdeen-based wireline specialist Wireline Engineering has recently been able to establish a base in Kuala Lumpur. The company's unique conveyance product – the Roller Bogie – had previously been regarded as not relevant to the older, more traditional wells in the region. However, the recent emergence of extended-reach, multilateral and high-angle completions has resulted in a significant increase in demand for a tool that enables intervention tool-strings to be run with virtually no friction-drag.

Patient and careful monitoring of the local market has allowed Wireline, and many companies like it, to take advantage of the changing circumstances of the Asia-Pacific market. High specification products are no longer seen as 'expensive North Sea equipment', but as real solutions to common problems experienced in technically demanding wells in the Asia-Pacific area.

New developments such as Murphy Oil's Kikeh field are just the tip of the iceberg. Petronas plans to raise production by 20% over the next 10 years – and not just in the Asia-Pacific region. The company has in recent years expanded its operations into 34 countries across the globe. Directly, and through various subsidiary companies, Petronas has an interest in more than 60 upstream exploration and production ventures in 26 countries. Developing new commercial partnerships with Petronas in Malaysia therefore offers a great opportunity to UK companies to follow it into developing oil and gas provinces outside the Asia-Pacific region, such as Sudan and Turkmenistan.

Be aware

Having indicated the opportunities becoming available, it would be remiss not to point out the special factors that need to be taken into account by UK companies considering the Asia-Pacific market.

Unsurprisingly, there are regulations governing the local environment that foreign companies are expected to comply with. These regulations vary from country to country within the region, but generally they expect foreign companies to help improve indigenous capabilities if possible, and often include this as a contractual obligation. Local representation is also a frequent expectation.

In practice, this can mean that developing local partnering agreements and joint ventures will be preferred to the traditional commission-based agent relationship. In addition, evidence of technology and knowledge-transfer benefits for the local market is becoming a requirement of many current contracts.

UK companies moving into this market in the last two years have quickly realised how important it is to make the correct decisions regarding local partners and agents. It takes time and thorough research to ensure that the local representative relationship they adopt is appropriate for their type of business.

The Asia-Pacific market tends not to offer immediate revenue-generating projects. Foreign companies must have a long-term mind-set before they enter this market. Success depends on sufficient energy and patience being applied to relationship building and to adapting products and services to local requirements. Indeed, rushing to appoint local representation could be highly counter-productive in the short-term and also hinder the development of a longer-term presence in the marketplace. This is where organisations such as Advisors Asia Pacific can make a real difference during the decision-making phase and beyond.

Aberdeen-based Cogent acknowledges that as a UK organisation it struggled for many years in the Asia-Pacific market because prospective customers in the local oil and gas industry did not appreciate the added value it could offer to their business. Fortunately, Cogent was willing to take the long-term view and patiently developed relationships in the region, slowly but steadily raising awareness of its services and latterly adapting its offering to meet local requirements.

Cogent's services were initially not seen as relevant to the needs of the regional industry. We, at Advisors Asia Pacific, were able to apply our specialist local knowledge and contacts to help Cogent devote time and carefully-targeted effort to demonstrate that it could genuinely add value to the training sector and accreditation in the region. The result is that Cogent's OPITO-branded training and consultancy services are now firmly established across the Asia-Pacific region, with a total of 14 fully-accredited training centres, up from two just four years ago.

The famous Petronas towers in Kuala Lumpur, where Cogent has established its Asia-Pacific regional office
Photo: Ian Laing

Key to success

There are many similar examples, all indicative of a growing presence for UK companies in the dynamic and fast-moving Asia-Pacific market. The key to success is, as with any unfamiliar territory, to thoroughly understand the local marketplace and be prepared to invest time and patient effort in developing local relationships. Agencies such as Advisors Asia Pacific already have the local contacts and knowledge, and can add real value.

With effort, patience and careful targeting, the rewards are there for the taking.

Benefits of a predictive maintenance system

Downtime due to equipment failure is expensive and inconvenient, sometimes even having disastrous consequences. Predictive maintenance is intended to reduce the number of unexpected failures to an absolute minimum by allowing maintenance staff to effectively 'see' the condition of the machine internals. The idea works by monitoring the condition of a machine whilst in service, with the intention of planning for maintenance before a failure occurs – but not too far in advance – so that the cost of replacement parts is minimised.

There are four principal, but complementary, technologies that are used in this process:

- Vibration analysis
- Oil analysis
- Acoustic emission
- Infrared thermography

Each of these technologies relies on collecting data at regular intervals, ranging from continuously to yearly depending on the running hours and the criticality of the equipment. The results are then monitored for change.

It is this change, together with the rate of change, that predictive maintenance programmes are looking for, since this can tell the operator far more than just observing absolute levels. In the case of vibration analysis, for example, it is not uncommon to initially find high levels of vibration (generally considered undesirable) only to find that these are the machine's natural running vibrations and that the machine is perfectly serviceable.

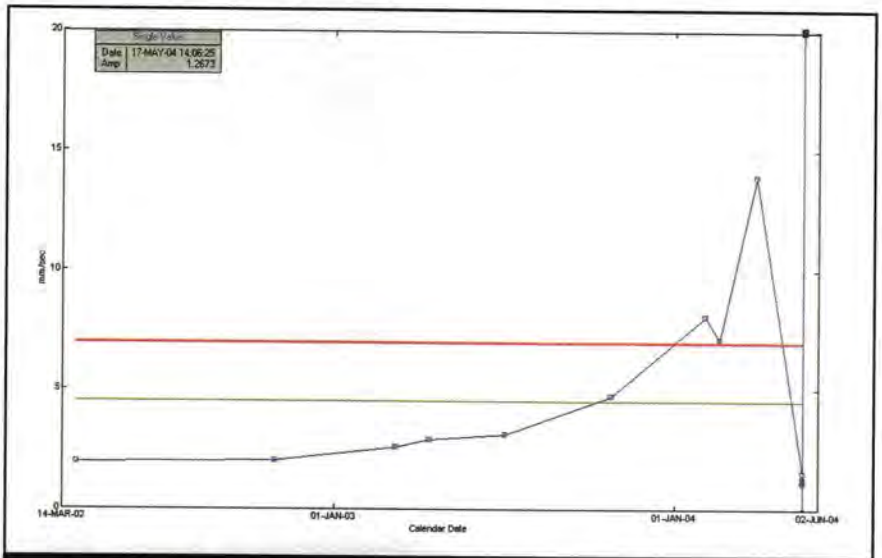

Figure 1: An example from a predictive maintenance system. The change in the machine's condition over time can be clearly seen – the yellow and red bands are alert and alarm limits which warn the operator to identify the fault and (at the very least) monitor more often

An example from a predictive maintenance system is shown in **Figure 1**. The change in the machine's condition over time can be clearly seen – the yellow and red bands are alert and alarm limits which warn the operator to identify the fault and (at the very least) monitor more often. However, it is the rate of increase of the trend over the last two readings which indicated that action had become essential. The machine was taken out of service and repaired before failure, avoiding an expensive unexpected shutdown. In this case, only coupling replacement was necessary.

Today, computers form an integral part of condition monitoring systems, with specialist software and data collectors being developed. These make the task of collecting and correlating data much simpler. However, interpretation of the information is a skilled job and it is important that a condition monitoring programme is set up correctly in order to gain the maximum benefit from it. Once running it is critical that the data collected is obtained in the correct manner.

Quality of training and lack of standardisation for condition monitoring practitioners have long been an issue for concern. The ISO standard 18436 overcomes this issue and the British Institute of Non-Destructive Testing (BINDT) has introduced a series of training courses and examinations that will demonstrate the individual's level of competence. It is foreseen that the ISO 18436 certification will become more prevalent and, for condition monitoring practitioners, it will effectively become compulsory as the demand from companies increases, in a similar manner to ISO 9000.

There are three levels of competence under the training scheme – ranging from level 1, at which an operative is capable of collecting consistently good data and recognising problems, to level 3, which only full-time specialists would normally be required to attain. Based in Lymm in Cheshire, Vibration Consultants and Instrumentation (VCI), claims to be the first approved organisation in the UK that can offer the BINDT training courses and examinations in Vibration Data Collection and Analysis. For more information, contact:

Disc coupling located between the turbine and gearbox showing the orginal balance adjustments and breakup of the disc stack, which resulted in the machine imbalance

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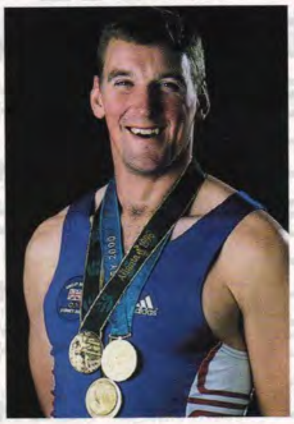
Guest Speaker and Presenter Matthew Pinsent, CBE



In the final of the men's Coxless Four at the Millennium Olympic Games in Sydney, Matthew Pinsent CBE, (right) won his third Olympic Gold Medal. 'THE RACE' in which he did it has been voted 'Britain's Greatest Sporting Moment' and the crew have secured themselves a very special place in the heart of the nation.

In 1992, at the age of only 21, Matthew had his first taste of Olympic success, when in a Coxless Pair with partner Sir Steve Redgrave, he won the Gold Medal at the Barcelona Olympics.

At the Olympics in Atlanta in 1996 the Pinsent/Redgrave duo won another Gold Medal and throughout the nineties their outstanding combination also brought them Seven World Championship Gold's.

Their unbroken run of successes continued through to Sydney 2000 when Pinsent, again with Redgrave (now in a Coxless Four with James Cracknell and Tim Foster) again triumphed earning Pinsent his third Olympic Gold Medal in the final of the Coxless Four.

Since Sydney, Matthew has formed a Coxless Pair partnership with James Cracknell MBE. Undefeated throughout 2001, they went on to complete a unique feat in the history of rowing, by winning the Coxless Pair at the World Championships in Lucerne, a mere two hours after winning the Coxed Pairs. In the 2002 World Championships in Seville they defended their Coxless Pairs title, breaking the world record by 4 seconds in the process.

Matthew was awarded the MBE in the 1993 New Year's Honours List and the CBE in the New Years Honours list 2000.

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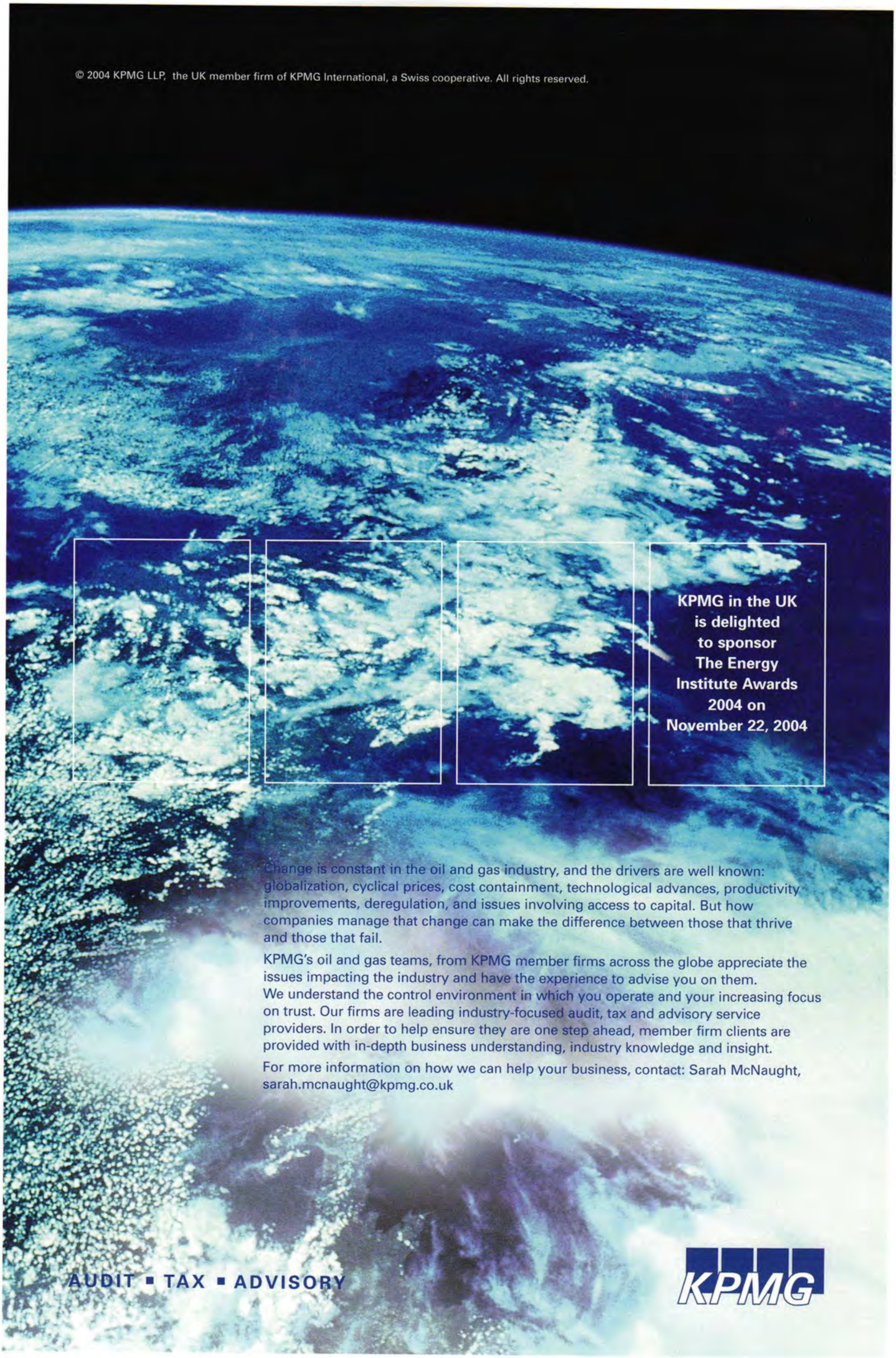
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