Petroleum review

DECEMBER 2004

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- Basking in the sun

Europe

- Creating an effective gas supply network

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: Two gas and two oil field developments will soon be underway offshore from Mount Taranaki. ***See p12 for full Australasia round-up.***

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ROUNDUP From the Editor

Dreaming of more access

Now that President Bush has secured a clear majority he is likely to press ahead with some or all of his Energy Bill which failed to secure Congressional backing in his first term in office.

Two projects are now being widely touted to address the increasing shortfalls in US oil and gas production. The first is a return to the Destin Dome gas field. This field was discovered in the late 1980s by a ChevronTexaco predecessor. Production was, however, blocked on somewhat confused pollution fears in Florida. Now, with neither President Bush nor Jeb Bush, the Governor of Florida, able to stand for re-election, the view is that this proved gas resource is seen as a route to reducing the shortfall in US gas production.

This shortfall in gas production has already produced very high prices and the effective destruction of capacity in a number of gas-based industries, including ammonia production, fertilisers and some petrochemicals. Latest spot prices are in the \$6.50–\$7mn Btu range, having recently been as high as \$9mn Btu.

The other sector to have been heavily pressured by high gas prices are the generators who built huge amounts of gas-fired generating capacity assuming prices would remain at around \$2mn Btu (where they had been for the entire 1990s). A truly spectacular failure to heed the warnings about the depletion of gas supplies and the naive assumption that higher prices would draw out more supply before the LNG supplies or Alaskan gas supplies arrived, have led to this debacle.

As the Destin Dome and more aggressive development of coalbed methane resources are really the only short-term palliatives to declining US gas supplies, we can expect both to go ahead.

One interesting question remains. As the Destin Dome licences were bought out and revoked, will they now be auctioned, or returned to their original owners. And who will pay who money?

The other and altogether more problematic incremental supply could come with the opening up of the ANWR (Arctic National Wildlife Refuge). Long a Republican objective, the opening of the ANWR has been passionately resisted by environmentalists and those who believed the refuge should be sacrosanct and closed to all development. For the oil industry, as opposed to the politicians, the key question is whether the ANWR is likely to contain enough oil to warrant the likely costs and environmental safeguards necessary to minimise social outcry and negative publicity. A potential output of up to 1mn b/d has been touted by Vice President Cheney during the election campaign.

A free-flowing productive reservoir can produce 7–8% of reserves at peak flows, so 1mn b/d – or 365mn b/y – requires 4.6–5.2bn barrels of reserves to be in production. Now, the usually accepted estimates for ANWR are a P90 of 2.8mn barrels and a P50 of 5.6mn barrels – so 1mn b/d is technically possible.

The state of Alaska, where residents pay no tax and receive an annual (but declining) bonus from oil taxes, is keen to see development. The Republicans (with some exceptions) are also keen to see development – but many others are reluctant to see the destruction of the principle of an inviolable wilderness area. As so often, the oil industry finds itself in the middle, keen for additional, politically secure supply, but equally eager to avoid being characterised as environmentally insensitive.

The current rumours are that the opening up of the ANWR is to be tagged onto a budget reconciliation bill in February. This would remove the possibility of the bill being filibustered (filibusters are not allowed on budget reconciliation bills) but would not necessarily resolve the problem of public opposition.

The efforts to expand US oil and gas production are, however, only part of a wider question – will US foreign policy continue to be essentially aggressive and unilateralist towards its perceived enemies or will the second Bush presidency be more consensual in its approach?

The resignation of Colin Powell and his replacement by Condolezza Rice will certainly bring an understanding of oil industry aspirations in international policy terms (Rice was previously a ChevronTexaco director), but, as a close confidant of President Bush, she is unlikely to bring a softer line to problems such as Iraq and Iran. Many in the oil industry dream of the day they have greater and easier access to the resources of the Middle East. It remains to be seen if the second Bush administration advances or retards that dream.

Chris Skrebowski

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

e world

OILspace, a technology company that provides web services applications, integration and market data distribution for trading, marketing and supply companies in the oil, natural gas and petrochemical sectors is now offering real-time foreign currency exchange (forex) rates via its OILwatch service, OILwatch is an Internet market data delivery portal for real-time and historical energy commodities news, pricing and analysis. It aggregates critical pricing feeds from the world's most respected global indices, including Nymex, IPE, Platts, Dow Jones, BBC Monitoring, Natural Gas Intelligence, Petroleum Argus, OPIS and more. It also integrates pricing settlements through the back-office, and features advanced charting tools used to track and forecast trends and transactions in today's volatile markets. For more information, visit **www.oilspace.com**

A new hazardous materials referencing website has been launched for shippers of dangerous goods in the US. The US government estimates that some 800,000 hazmat shipments are made daily, with 40,000 of those being moved by air. With this in mind **www.hazmatlaw.com** has been created to assist shippers with the safe and compliant passage of these goods. The site has a dedicated section for regulatory developments, classification and packaging group information as well as notification of regulatory exemptions and government enforcement procedures.

On behalf of ICRARD, a forum of authorities, the Petroleum Safety Authority Norway (PSA) has developed **www.icrard.org** – which provides a global overview of research and development projects in the fields of health, safety and the environment (HSE) within the petroleum activities.

Genscape – **www.genscape.com** – has launched Power Europe, a web-based service providing customers with electricity generation and transmission flow data for facilities in the most important Continental European power trading markets. Wholesale electricity producers, traders and consumers will have access to detailed supply side information that serves to enhance market transparency and improve risk management. The service will initially provide information for facilities located in the Netherlands, Germany and France.

A new next day pallet network dedicated to the movement of hazardous goods throughout the UK has been launched. For more information on the Hazchem Network, visit **www.hazchemnetwork.co.uk**

In Brief

UK

BG Group and partners Centrica and *Total have announced the successful appraisal of the formerly fallow Maria discovery 16/29a-11Y in the central North Sea, adjacent to the Armada development. BG is operator, with a 36% interest, with Centrica holding 35.04% and Total 28.96%. Recoverable reserves for Maria and the adjacent Maria Horst prospect are estimated at 35mn barrels. First production is scheduled for late 2006/early 2007, subject to relevant approvals. During testing, the well flowed at 6,720 b/d of oil.*

Shell UK, on behalf of co-venturers *Petro Summit Investment UK and OMV (UK), has reported that oil production has commenced on schedule from the Howe field in central North Sea block 22/12a. The field is tied back to the Nelson platform through a 14-km subsea tie-back. Production is expected to plateau at around 13,000 boe/d.*

EnCana Corporation is to sell its sub*sidiary EnCana (UK) to Nexen for approximately $2.1bn in cash. EnCana (UK)'s interests include a 43.2% stake in the Buzzard oil field, a 41% and 54.3% interest, respectively, in the Scott and Telford oil fields, other satellite discoveries, plus interests in exploration licences covering more than 740,000 net acres in the North Sea. Proved reserves at 31 December 2003 associated with the UK operations were 129mn boe. EnCana plans to sharpen its focus on North American gas and oil sands.*

Europe

BP is seeking offers for its 10.34% *interest in the Ormen Lange gas field, offshore Norway, and its 10.2% stake in the 1,200-km Langeled gas export pipeline. The company hopes to reach agreement on a sale by the end of 2004 with completion early in 2005. The Ormen Lange field is the second largest gas field on the Norwegian Continental Shelf, with reserves of some 14tn cf (397bn cm) of gas. First production is expected in 2007.*

North America

Anadarko Petroleum is to sell its south*east Colorado producing properties to an affiliate of Citation Oil & Gas for $107.6mn. The producing property package includes an estimated 9mn*

NEWS Upstream

Frigg decommissioning

Aker Kvaerner Offshore Partner has been awarded a NKr3bn contract by Total E&P Norge for the engineering, preparation, removal and disposal of the Frigg field installations located on the Norwegian and UK continental shelves. Aker Kvaerner Offshore Partner will be the contract partner in a consortium of both Norwegian and UK companies, including Saipem UK, Shetland Decommissioning Company, Aker Stord and Aker Marine Contracting.

All topsides and steel jackets are to be removed. The detail planning of the removal operations on Frigg starts immediately. Next summer, between 13,000 and 14,000 tonnes of steel from the TCP2 gas handling and compressor platform in the Norwegian sector, as well as some smaller units from the living quarter, QP, in the UK sector, will be taken onshore.

During the period 2005–2008 Aker Kvaerner will remove nearly 85,000 tonnes of steel from the Frigg field, almost 20,000 tonnes of which will be taken to Shetland for dismantling at its Greenhead base, while the rest will be taken onshore at Stord, Norway. All the steel will be recycled.

In addition to the steel topsides on the TCP2 platform, DP1 and the entire drilling platform DP2 on the Norwegian sector, the contract includes all the living quarters and the steel topsides on the TP1, MCP-01 and CDP1 platforms in the UK sector.

The Frigg field has been in operation for 27 years – from September 1977 until this autumn.

New petroleum systems in Jamaica

A major new investigative report into the geology of Jamaica has discovered what seems to be a previously unknown active petroleum system, Jamaican Energy Minister Philip Paulwell recently reported. The country is to soon launch its first-ever block licensing round, offering 22 offshore blocks and four onshore blocks.

In the past a significant petroleum system in Jamaica has remained elusive due to limitations of technology at the time. The focus had been primarily on rocks of Cretaceous age. Through modern analytical techniques and thinking the new revelation has, instead, identified more significant source rocks in the Tertiary period. Project geologist Nick Cameron noted that there is a striking geological similarity between Jamaica's Walton Basin and the active Malampaya gas field in the Philippines and the Tertiary petroleum systems of south-east Sumatra and north-east Java.

To date, 53 structures have been identified offshore in modest water depths. Of the 11 exploration wells drilled so far (two onshore, nine offshore) ten have revealed either oil or gas shows.

Fabrication for Equatorial Guinea block

MODEC International has signed a contract with Amerada Hess for the design, engineering, procurement and construction of the hulls, topsides, mooring, drilling riser and production riser systems for two tension leg platforms (TLP) for Amerada's Equatorial Guinea northern block G development.

The Oveng and Okume/Ebano reservoir areas will be developed using the TLPs. The Oveng TLP is planned to be installed in approximately 280 metres (900 ft) of water and is capable of supporting up to 18 top tensioned production and/or water injection risers, a tender-assist drilling unit, and topsides. Hydrocarbons will be routed back to the central process facility (CPF).

The Okume/Ebano TLP is planned to be installed in approximately 500 metres (1,650 ft) of water and is also capable of supporting up to 18 top tensioned production and/or water injection, with rig and topsides capabilities similar to the Oveng TLP. The facilities are scheduled to be installed in 2Q2006.

'The award of the third and fourth MODEC TLPs builds on the previous success of the innovative MOSES Design and opens the door to the West African market for MODEC. This particular design also offers a step change in our hull concept. These new hull designs have enough free-floating stability to allow the deck to be integrated with the hull in the shipyard. This design eliminates the need for lifting and setting of the deck structure offshore and does so without using expensive temporary stability modules,' said Ray Koon, Vice President.

New gas for Syntroleum in US

Syntroleum Corporation reports that it has successfully tested its first gas well as part of a previously announced low-Btu gas initiative. Under the initiative, Syntroleum will drill and produce natural gas in the US that was previously bypassed or under-produced due to high inert content. This domestic natural gas business parallels the international gas-to-liquids (GTL) business, both of which focus on stranded gas. GTL technology converts gas-to-liquid diesel fuel whereas this domestic business simply removes inert gases resulting in pipeline quality natural gas.

'This well is the first step in the execution of our strategy to develop domestic stranded gas,' commented Syntroleum President and Chief Operating Officer, Jack Holmes. 'The results of this well have exceeded our expectations for deliverability in this area.' Syntroleum logged and tested gas in the company-operated 1-1 Colberg 19-9 well in Rice County, Kansas. The productive interval at a depth of 2,459 ft flowed at rates between 1.2mn and 2.3mn cf/d of gas with approximately 40% nitrogen. The experience in the area is that these wells will see an exponential decline in gas rate in the first year and then stabilise at a lower rate for longer periods.

Syntroleum has leased over 64,000 acres with 100% working interest and over 85% net revenue interest in Rice, Reno, Stafford, and Ellsworth counties in central Kansas. Within the outline of this acreage more than 50 wells have been drilled since the 1960s that tested natural gas with high nitrogen content.

Based on the current geologic and engineering data, the company plans to develop this acreage on 160-acre spacing. The ultimate development plan could be modified based on the results of subsequent drilling. 'The key to monetising this gas is to remove the nitrogen or other inert gases using one or more technologies to achieve pipeline quality' states the company. 'Over the past two years Syntroleum has evaluated numerous nitrogen and CO_2 removal technologies for lower rate gas wells. The first plant has been ordered and is expected to be delivered and operational early next year.'

Robust global subsea production market

Quest Offshore's year-to-date (October 2004) statistics for the global subsea production market has revealed a robust year-to-year increase of 63% compared with the first nine months of 2003 – 279 subsea trees versus 171 subsea trees, respectively. West African orders represented a 41% share, followed by the North Sea and Brazil with approximately 20% each. The Asia-Pacific and US represented just less than 20% of total market activity.

The Gulf of Mexico experienced a resurgence of activity, with a total of 14 projects tabulated during the quarter representing a 30% share of total market activity. Independents led activity, including Kerr-McGee, Dominion E&P, LLOG, Mariner Energy, Amerada Hess, W&T Offshore, Newfield Exploration, Tarpon Operating and Hunt Oil. Meanwhile, Total's Rosa project in West Africa and orders for Petrobras represented nearly one-half of activity during the quarter. A majority of the activity, 52%, was characterised by small one-to-three well subsea tieback projects in Egypt, Australia, the North Sea and Gulf of Mexico. Manufacturer's market share for 3Q2004 was 52% FMC, 23% Cameron, 13% Vetco Gray, 8% Aker Kvaerner and approximately 5% Dril-Quip.

Quest Offshore has raised its market projections for global subsea tree orders in 2005 to 352 (up from 335). Active areas identified for 2005 are projected to be West Africa, with approximately 42% of subsea tree orders, followed by the Gulf of Mexico 17%, Asia-Pacific 16%, North Sea 10%, and Brazil/Latin America 15%.

Centrica acquires Hawkeye Exploration

Centrica has reached agreement with Tullow Oil to acquire Hawkeye Exploration, which owns a 50% interest in the undeveloped Horne and Wren gas fields in the southern North Sea. The acquisition is expected to add approximately 230mn therms to Centrica's equity gas portfolio. First gas is scheduled for summer 2005, with reserves being extracted over a two-year period. Centrica will make an anticipated payment of £7.1mn, of which £4.6mn will be paid immediately. Its share of the development cost is estimated at £24mn. This acquisition will also benefit Centrica through tariff income received via its interests in the Thames field (10%) and the Hewett Bacton terminal (23.15%) through which gas from Horne and Wren will be transported.

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boe of proved reserves, with a current net production of approximately 3,000 boe/d. They are about 80% operated, with approximately 90% of the proved reserves classified as oil.

***Talisman Energy has drilled another** successful Paleozoic gas well in its core Monkman area in north-eastern British Columbia. The well tested at a restricted rate of 40mn cf/d and should be in production by 1 January 2005. Based on flow rates and pressure data current indications are that this well could have upwards of 200bn cf of original gas in place. The company also recently purchased deep gas mineral rights on 3,800 hectares of offsetting Crown Land for $7.9mn. The land is along trend to the north and west of the 60-E discovery.*

***Fortuna Energy, a wholly owned sub**sidiary of Talisman Energy, reports that the Soderblom HZ #1 natural gas well in the Appalachian Basin of New York state flowed on test at rates in excess of 19mn cf/d, limited by surface equipment. Based on initial flow results, the Soderblom well could be equivalent to the Reed HZ #1 well, which was brought onstream in the spring 2004 at a rate of 34mn cf/d and has produced 5.3bn cf to date.*

***ChevronTexaco (58%, operator) has** reported that a test of its Tahiti discovery well in Green Canyon block 640 in the Gulf of Mexico has indicated that production from this well could be as much as 30,000 b/d of oil. The well's peak rate during the production test reached 15,000 b/d. Tahiti partners are EnCana (25%) and Shell (17%).*

***Kerr-McGee and Stone Energy have** entered into exploration agreements covering interests in 30 leases held by Kerr-McGee in the Gulf of Mexico. Under the terms of the agreements, Stone acquires working interests ranging from 16.67% to 50%, while Kerr-McGee remains operator and retains working interests from 50% up to 75%. In addition, Stone will participate with Kerr-McGee in at least six exploratory wells in the Gulf of Mexico through the end of 2005. Stone has committed approximately $50mn to cover its share of costs to date and future drilling commitments.*

Middle East

***A new oil field is reported to have** been found in Abu Sadar, 175 km*

In Brief

south of Riyadh in Saudi Arabia. Discovered by Saudi Aramco, the field is expected to produce some 3,000 b/d of oil.

***Eni (operator, 60%) reports that pro**duction from phases 4 and 5 of the South Pars gas and condensate project in Iran has started up. The South Pars field, located in the Iranian waters of the Persian Gulf, will initially produce 14mn cm/d of gas; rising to 58mn cm/d (20bn cm/y) at full capacity. Partners in phases 4 and 5 are Petropars (20%) and Naftiran Intertrade Company (NICO) (20%) on behalf of the National Iranian Oil Company.*

Russia & Central Asia

***Kazakhstan's Minister for Energy,** Vladimir Shkolnik, has announced that the country has reached a preliminary agreement with consortium partners Eni, BG, Total, ExxonMobil, Shell, ConocoPhillips and Inpex on its bid for British Gas's 16.67% share in the Kashagan project. No further details have been released. Kashagan has estimated in-place reserves of 45bn barrels, of which between 8bn and 13bn are considered recoverable.*

***Eni subsidiary Saipem has been** awarded a contract for the construction and installation of the offshore pipeline system as part of the Kashagan field development in the Kazakh sector of the Caspian Sea. Saipem will install the pipeline system between 2006 and 2007 with a new lay barge and new trenching equipment.*

***Oil and gas service company** Schlumberger is reported to be removing its equipment from Yukos operations – in a move that is expected to reduce daily production from Yuganskneftegaz, the main Yukos subsidiary, by 8% by the end of October. Yukos first began cooperating with the French company five years ago. Since then, Schlumberger technologies have enabled the Russian company to boost annual oil production from its assets by between 10% and 20%.*

***Sakhalin Energy Investment – a joint** venture between Shell, Mitsui and Mitsubishi – has awarded ABB a contract worth almost $100mn. ABB is to design and construct two modules and supporting equipment for the Molikpaq oil platform, located off the east coast of Sakhalin Island, which will facilitate the export of oil and gas*

NEWS Upstream

Another fall in UK oil production

UK oil production continued to decline in August, down by 7.8% on the month and 12.7% on the year at 1,621,582 b/d, according to the latest (November) Royal Bank of Scotland *Oil & Gas Index*. However, the continued strength of oil prices helped maintain revenues at levels above those of 12 months ago, with the monthly average price per barrel reaching $42.99 in August.

Gas production also decreased by 14.2% on the month and by 6.9% on the year, at 8,800mn cf/d.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Aug 2003	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	10,192	35.21
Jul	1,758,312	10,260	38.15
Aug	1,621,582	8,800	42.99

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Green light for Saturn (Annabel) project

The UK government has given Venture Production the green light for the development of the Saturn (Annabel) gas accumulation, part of the larger Saturn development area in the southern North Sea. It is anticipated that production from Saturn (Annabel), via a subsea tieback to the Audrey 'A' platform, will start during 1Q2005. Initial rates will be constrained to between 60mn and 70mn cf/d. In order to accelerate and maximise recoverable reserves, Venture is planning to drill a second well on the Saturn (Annabel) accumulation in 3Q2005. Gas export will be via the existing LOGGS infrastructure and into the Theddlethorpe terminal in Lincolnshire.

In addition to this near term production increase, the recent offer of an award of a promote licence for block 48/15b in the 22nd licensing round gives Venture the opportunity to consider further near-field exploration to the south of the current development.

First production from ROD project

BHP Billiton reports that production has commenced from the ROD integrated development project in eastern Algeria. During the first phase of production some 18,000 b/d of oil is currently being produced from the ROD field through the neighbouring BRN processing facility. Following the completion of the ROD central processing facility later this year, production will rise to 80,000 b/d of Saharan Blend crude oil. The ROD integrated development consists of the development of six satellite oil fields in the Berkine Basin. Associated gas and water will be reinjected into the reservoir to provide pressure support to the reservoir. A total of 34 development wells have been drilled and are available for production operations.

Philip Aiken, Group President Energy, said: 'The ROD integrated development represents our second development in Algeria. ROD and the Ohanet development have given us a platform for growth and we are delighted to have acquired further exploration acreage in blocks 408a/409 in the recent fifth Algerian international bid round.'

The capital cost of the project is forecast to be within the original budget and BHP Billiton's share is $192mn. BHP Billiton has funded 36.04% of the capital project and Eni the remaining 63.9%. Sonatrach and BHP Billiton are the joint operator of the development phase, while the production phase will be jointly operated by a Sonatrach and Eni.

Voice against new UK tax proposal

Responding to calls by the trade union Amicus for the UK Treasury to impose a tax on companies who fail to explore for new oil and gas in the North Sea, Mike Tholen, Economics and Commercial Director at the UK Offshore Operators Association (UKOOA), said: 'Amicus will not be able to produce a single company investing in the UK today, nor a single company that would like to invest in the UK, that will support their tax proposals. Far from securing the future of the North Sea, Amicus would appear to be calling for a repeat of a failed recipe that has already been shown to cause a slowdown in investment.'

'The industry is now recovering from two exceptionally disappointing years that followed the unexpected tax hit on oil and gas producers in 2002. Investor confidence is returning to the North Sea as the tax regime is being seen to be more predictable, with evidence of more exploration wells being drilled this year, more field developments going ahead and demand for drilling rigs pushing up rates to their highest in two years, with five rigs being recommissioned this year to support the heightened activity.'

'There are now also more new oil and gas fields being considered for development within the next three years than at this time last year, a significant number of them involving new smaller operators. Recent initiatives to encourage activity in fallow or dormant acreage are proving successful, as have been the new lower-cost licences introduced by government to stimulate fresh interest and exploration. These have attracted particular interest from companies who are new to the UK. Established companies are active too. Shell has announced [in October] that it has produced the first gas from the Goldeneye field in the Outer Moray Firth, a £300mn project which will provide around 3% of the UKs gas supply and secure thousands of jobs in Scotland.'

'Amicus' report is out-dated. They have failed to notice the renewed optimism and energy in the North Sea. Its proposals are out of touch with reality and worse, could do lasting damage to the industry, cost investment and jobs and reduce the industry's competitiveness at a crucial stage in its life cycle.'

Range of global contracts for KCA Deutag

KCA Deutag, a subsidiary of Abbot Group, has been awarded $67mn of contracts from clients operating in the Middle East, West Africa, Caspian Region and Asia. In Bahrain, a contract has been signed with the Bahrain Petroleum Company (BAPCO), the state-owned oil company for a 20-month drilling and workover programme commencing December 2004. In the UAE, the company has secured its first contract for the newly upgraded $9.6mn, 3,000hp rig T-79. The rig has been contracted by Margham Dubai Establishment (MDE) to drill a well in the Margham field in Oman. In Qatar, RasGas Company and Dolphin Energy have awarded a contract for rig T-67 to drill four wells, with a possible option on four additional wells, commencing November 2004.

Looking to the Asia-Pacific region, Brunei Shell Petroleum has awarded a two-year contract, with two one-year options, for the provision of a rig and drilling operations as part of the Menang drilling programme. A 350-tonne capacity rig is being built for the contract. Meanwhile, a contract to supply project management services for the Pasni 2 exploration well has been awarded by Pakistan Petroleum.

Elsewhere, in Baku, the Azerbaijan International Operating Company (AIOC) has announced awarded KCA Deutag a $10mn contract for the engineering and procurement of drilling, utilities and quarters (DUQ) modules as part of the Phase 3 development of the Azeri, Chirag and deepwater portion of the Gunashli (ACG) full field development project.

Saudi and Kuwait working together

Saudi Arabia and Kuwait are understood to be planning to spend $1.6bn during the next five years in order to increase oil output from their shared offshore fields by about 17%, to 350,000 b/d. The two countries currently produce 300,000 b/d from the al-Khafji offshore field and could increase output by producing from the Hout, Dorra and Lulu, al-Awad fields.

The Hout oil field was shut down in 1998, while Dorra and Lulu haven't been developed because Iran, Saudi Arabia and Kuwait have yet to delineate disputed territorial waters. The offshore area is reported to contain more than 3bn barrels of recoverable oil reserves and more than 5tn cf of gas.

In Brief

via a newly installed pipeline system. Work is due to complete in 2006.

Asia-Pacific

***CNOOC reports that the Bonan fields** in the southern Bohai Bay have come onstream, producing about 4,200 barrels of oil and 1.4mn cf of gas from Bozhong 28-1 and Bozhong 26-2.*

***Oil & Natural Gas Corporation of India** is reported to have said it will lease out 19 offshore oil fields that are too small for the company to operate. No further details are available.*

***Talks between Australia and East** Timor have reached deadlock once again after both sides failed to agree on how to split the revenue from the Greater Sunrise field in the Timor Sea. There are now fears that unless agreement is reached soon, the project could be shelved.*

***Anadarko Petroleum has been** awarded exploration and production rights to the offshore North East Madura III block in Indonesia's fourth licensing round. Under terms of the standard production sharing contract to be entered into with BPMIGAS by year end, Anadarko will undertake a six-year exploration phase and 20-year production phase. During the initial three-year work programme Anadarko plans to acquire a minimum of 2,560 sq km of 3D seismic and drill six exploration wells.*

***Singapore Petroleum (10%) and its** partners Petronas Carigali Overseas, PetroVietnam and ATI Petroleum are reported to have discovered oil and gas in the Gulf of Tonkin, with their first oil exploration well in Vietnam. Additional wells are to be drilled to appraise the find.*

Africa

***Following the Koula discovery made** in September 2004, Shell Gabon and its co-venturer Pan-Ocean Energy have made a second light oil discovery in the exploration well AWODAM001 drilled on the flank of the Damier prospect in the Awoun permit, some 4 km south-west of Koula. The two discoveries are located 8 km to the north of the Total/Shell producing Avocette field, and 5 km to the north-west of Pan-Ocean's producing Obangue field.*

In Brief

UK

***The UK's oil trade balance moved into** deficit in September for the first time in 13 years, according to the Office for National Statistics (ONS).*

Europe

***Statoil achieved an income before** financial items, other items, income taxes and minority interest of NKr16.1bn for 3Q2004, a rise of 32% from the same period of last year.*

***Norsk Hydro has posted a 3Q2004** income from operations of NKr2,480mn, compared with NKr2,005mn in 3Q2003.*

North America

***TransCanada and Shell have just** announced plans to develop an offshore LNG regasification terminal, named Broadwater Energy, in the New York State waters of Long Island Sound. The proposed terminal would be capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately 1bn cf/d of natural gas. Broadwater Energy will operate the facility, while Shell will own the capacity and supply the LNG. The estimated cost of construction is approximately $700mn. For more details, visit* **www.broadwaterenergy.com**

***ChevronTexaco has signed an initial 20-** year agreement with Sabine Pass LNG – a subsidiary of Cheniere Energy – to secure 700mn cf/d of regasification capacity at Cheniere's Sabine Pass LNG terminal. Under the terms of this agreement, ChevronTexaco also has the option to obtain a 20% limited partner interest in Sabine Pass LNG.*

***Construction is underway on Anadarko** Petroleum's LNG terminal at Bear Head, Nova Scotia, Canada. The terminal is one of the most advanced new LNG projects in North America and is expected to be complete by late 2007.*

***ChevronTexaco has reported a 3Q2004** net income of $3.2bn, compared with net income of $2bn in last year's third quarter. ConocoPhillips posted a 3Q2004 net income of $2bn, up 54% from 3Q2003, while Amerada Hess reported a 3Q2004 net income of $178mn (3Q2003: $146mn), Marathon Oil $296mn (3Q2003: $293mn), Unocal*

NEWS Industry

Unification of Shell businesses is proposed to clarify operations

The Boards of Koninklijke Nederlandsche Petroleum Maatschappij (RD) and the Shell Transport and Trading Company (ST&T) have unanimously agreed to propose to their shareholders the unification of the Royal Dutch/Shell Group of Companies under a single parent company, Royal Dutch Shell plc. Real reforms in management and governance structure are also planned. The Boards believe that implementation of these proposals will clarify and simplify operations by having one listed company, with one Board, one Chairman and one Chief Executive; increase efficiencies by streamlining decision-making, with clear lines of authority and an empowered Chief Executive; and provide clarity in governance, reporting relationships and responsibilities. The new single parent company would be incorporated in the UK and headquartered and tax resident in The Netherlands.

Under the proposal, RD shareholders will be offered 60% of the issued share capital of Royal Dutch Shell and ST&T shareholders will be offered 40%. Jeroen van der Veer will become the first Chief Executive of the Group, while Aad Jacobs will be the non-executive Chairman until his previously planned retirement in 2006 when it is envisaged that he will be succeeded by an external appointee.

BP and Shell post rising 3Q profits

BP has reported that replacement cost operating profits in 3Q2004 rose to $3.9bn, an increase of 43% over the same period last year. Underlying return on average capital employed was at 21.5% and cash proxy returns were 36%, both up significantly.

During the quarter, the E&P segment produced oil and gas at an average rate of 3,906,000 b/d, up over 11% on last year. The group's investment in TNK-BP contributed 945,000 b/d. Full-year production is forecast to be around 4mn boe/d. BP's new production facilities – Atlas methanol in Trinidad, In Salah in Algeria, Train Four of the North West Shelf and Kizomba A in Angola – were reported to all be up and running, with the Holstein field in the Gulf of Mexico and the Clair field in the UK on schedule to come onstream later this year.

Looking at the oil price, BP Chief Executive Lord Browne said that he believe that 'on the basis of the recent track record and the supply-demand balance, oil prices have a support level of around $30/b for at least the medium term, underpinned by Opec discipline and their needs for revenue'. He also stated that BP would continue to use a Brent oil price of $20/b for the purposes of planning its activity levels in the E&P sector.

Meanwhile, Shell reported a 3Q2004 net income of $5,397mn, more than double the earnings in the same period last year. The Group's CCS earnings for the quarter of $4,407mn were 70% higher than the same period last year, reflecting higher hydrocarbon realisations, strong LNG and gas-to-liquids earnings offset by lower other income in gas and power, and higher downstream earnings in oil products and chemicals.

Exploration and production segment earnings of $2,405mn were 18% higher than a year ago. Earnings included a $183mn charge related to the market-to-market valuation of certain long-term UK gas supply contracts. Higher oil realisations (39%) and gas realisations (7%) were partly offset by the impact of hurricanes in the Gulf of Mexico and higher costs.

Mitsui takes stake in Mexican LNG terminal

Mitsui is to acquire a 25% stake in the LNG terminal in Altamira, Mexico, which is currently owned by Shell (75%) and Total (25%). Upon completion of the transaction – which is subject only to approval of the Mexican authorities – the equity interests in the LNG terminal will be Shell 50%, Mitsui 25% and Total 25%.

All of the terminal regasification capacity continues to be contracted to a separate marketing company owned by Shell (75%) and Total (25%). Last year Comisión Federal de Electricidad (CFE) awarded this marketing company a contract to supply 5bn cm/y of regasified LNG (equivalent to 3.6mn t/y) for 15 years, starting in October 2006.

The Shell-led project will be the first new LNG regasification terminal built in North America for over 20 years and is expected to start operations in 4Q2006. Depending on the growth in demand for natural gas in north-east Mexico, the terminal could be expanded to 10mn t/y.

Developments in the European Union

The dominance of fossil fuels in energy production is set to continue for the next 30 years, even growing a little, the European Environment Agency (EEA)'s latest 'environmental signals' report has predicted. Despite the European Union's (EU) efforts to promote renewable energy, it is 'not expected to raise its share significantly' of energy production sources, while 'nuclear energy is projected to decline', it predicted. Meanwhile, the European Commission has called for more investment in renewable energies after 2001 figures showed oil accounted for 40% of all EU energy sources, gas 23% and renewables 6%. The EU wants renewables to command 12% of its energy sources by 2010.

In other EU news stories, *Keith Nuthall* reports that:

- Outgoing EU Energy Commissioner Loyola de Palacio has visited Syria, pressing its government to reform its gas infrastructure and regulation so it can play a key role in creating a Middle East-to-Europe network. The European Commission (EC) sees Syria as a key link, notably in the so-called Arab pipeline linking Egypt to Syria and the Lebanon through Jordan. De Palacio noted that connections between Syria and Turkey could also 'open up the enlarged [eastern Europe] EU energy market'. De Palacio encouraged technological cooperation and the 'convergence of regulatory and normative standards'. She also visited the Lebanon to discuss developing its energy sector.
- A European Reference Materials (ERM®) seal has been launched, based on a quality assurance system operated by the EU's Institute for Reference Materials and Measurements (IRMM). It could guarantee low-sulphur claims in fuel, for instance.
- Russia has promised to raise its natural gas price for industrial users so it 'covers costs, profits and investment needed for exploitation of new fields' in a wide-ranging trade deal with the EU helping Moscow's World Trade Organisation (WTO) membership application. Prices would rise from the current \$27–\$28/1,000 cm to between \$37–\$42 by 2006 and \$49–\$57 by 2010, although this mirrors Russia's existing energy strategy.
- The EU has pressed the Ukraine at an EU-Ukraine Cooperation Council for further energy sector reform, supporting the construction the Odessa-Brody oil pipeline.
- The EC has expanded its 50mn CIVITAS programme, providing 35% funding for projects reducing urban road transport to eastern Europe, including cities from Estonia, Hungary, Poland, Romania and Slovenia.
- Diesel vehicle owners are undermining the efforts of manufacturers to reduce road transport pollution in Europe, a European Environment Agency (EEA) report has claimed, by tuning engines to boost their power. The EEA thinks up to 50% of new diesel vehicles are being modified and that such changes can increase emissions, especially of harmful particles, by as much as three times. The problem is particularly acute given that 15% of the reduction in carbon dioxide emissions achieved in Europe since 1995 is due to the increasing sales of fuel-efficient diesel cars. Generally, improvements in fuel and engine quality have cut land transport emissions by 24%–35% in EU countries from 1990 to 2001.
- Incoming European Commission President José Manuel Barroso has moved Hungary's Lazlo Kovacs from being Energy Commissioner-designate, after he was criticised by the European Parliament for being 'professionally incompetent' in the field. He will now become Tax Commissioner and will be replaced by Latvia's Andris Piebalgs, a former Education and Finance Minister.
- The European Commission has withdrawn its proposal for an EU oil stocks crisis management system because of opposition from member states to giving Brussels powers over reserves.
- EU Energy Commissioner Loyola de Palacio and energy ministers from the Middle East and north Africa have launched the Rome Euro-Mediterranean Energy Platform (REMEP). A key priority is integrating Levant gas systems, eventually linking them with the EU.
- France has been criticised by EU states for unilaterally rebating additional tax revenues generated by rising oil prices to the industries suffering the most from the price hikes, such as hauliers.
- Portugal and Austria have been censured by the European Court of Justice for insufficiently prioritising the re-use of oil, breaking the amended directive 75/439/EEC.
- The first national reports on implementing directive 2003/30/EC on promoting biofuels or other renewable fuels have been released by the Commission.

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\$330mn (3Q2003: \$152mn) and Anadarko Petroleum \$399mn (3Q2003: \$274mn).

Woodside Energy and Crystal Energy *have agreed in principle to develop the proposed Clearwater Port LNG import terminal off California. The terminal is being designed to accept a base capacity of 6mn t/y of LNG (800mn cf/d).*

Russia & Central Asia

Slovakia is understood to have said *that it is ready to negotiate with Russia to regain a 49% share of the former state-owned petrol company Transpetrol, which is currently owned by Yukos.*

Gazprom has set up a new daughter *company – Gazpromneft – appointing Rosneft President Sergei Bogdanchikov as its new Director General.*

The Sakhalin II project partners have *signed a sales and purchase agreement (SPA) for the supply of 1.5mn t/y of LNG over 22 years to Tokyo Electric Power Company – Japan's largest power company. LNG will be supplied to Tokyo Electric from Sakhalin Energy's major new LNG plant, which is under construction at Prigorodnoye on Aniva Bay on the southern tip of Sakhalin, just two and a half day's sailing from Tokyo Bay in Japan. It is the first LNG plant to be built in Russia and will have a total capacity of 9.6mn t/y.*

Russia has ratified the Kyoto Protocol, *which aims to help slow down global warming. Russia's ratification has been the key to Kyoto's coming into force since 2001 when the US pulled out of the pact. The Protocol stipulates that it must be ratified by industrialised countries whose combined 1990 emissions exceed 55% of that group's total. With Russia accounting for 17% of emissions, it was the only country outside of the US who could push the agreement over that threshold and bring the Protocol into force.*

International law firm Salans, through *its US subsidiary SHH International, has concluded a major contract to advise on the restructuring and commercialisation of Socar, the state oil company of Azerbaijan. The project is funded under a USTDA (US technical development agreement) grant administered by the EBRD (European Bank for Reconstruction and Development).*

In Brief

UK

The UK currently has two trade associations representing the lubricants industry – the British Lubricants Federation (BLF) and the UK Delegation to the Independent Union of the European Lubricant Industry (UEIL UK). Both organisations have expressed a wish to see a single trade association representing their interests. BLF is to formally ask its members to agree a number of resolutions in order to begin the transformation at an EGM on 9 December.

The IPE (International Petroleum Exchange) began exclusive electronic trading of its benchmark Brent Crude contract on 1 November 2004.

Centrica has commenced an energy tolling agreement with the owners of a new gas-fired power station at Spalding, Lincolnshire, which will deliver an additional 860 MW of electricity to supply British Gas customers. The Spalding unit, together with Centrica's own power station portfolio, is capable of meeting approximately 55% of the group's peak residential demand, based on 2005 projections. Spalding is a recently commissioned high-efficiency plant, which will use established technology and is designed to operate in a flexible, non-baseload regime.

Europe

EOS Technologies, which currently manages what it claims to be the world's largest oil and gas industry procurement exchange with over 4,000 members worldwide, has unveiled its new European Energy Exchange. The European energy industry is estimated to generate about 30mn procurement related documents every year. EOS claims that by using the new exchange the industry will potentially save over $3bn/y on process and transmission costs. The new exchange also increases EOS' exchange membership to over 8,000 organisations and provides it with a springboard to 'kick-start' its other energy exchanges in Russia and the CIS, as well as in the Middle East.

North America

Valero is to acquire Kaneb Services and Kaneb Pipe Line Partners for $2.3bn in

No guarantees for cheaper UK gas

Deregulation of continental energy markets will not guarantee cheaper gas in the UK, claims ILEX, a leading independent energy consultancy, in a recent report. Despite efforts to liberalise markets in Europe, gas prices are likely to remain linked to oil and, in the UK, this could mean wholesale prices persisting above 30 pence/therm unless the price of oil falls substantially. The ILEX report *Gas Prices in the UK* was commissioned in July by the UK Offshore Operators Association (UKOOA). It reviews the recent price increases in the UK market and assesses where gas prices might move over the next few years taking account of a tightening of the UK gas supply/demand balance and the impact of the UK gradually becoming a net gas importer.

The report's conclusions challenge the assumption that a more liberalised European gas market will lead to a full decoupling of the historic link between oil and gas prices, the principal driver behind the recent rises in wholesale gas prices in the UK. ILEX points to the highly competitive US energy market, where a link between gas and oil prices has re-emerged since 1998.

According to ILEX, UK gas prices to 2010 will continue to track the oil price and, assuming a price per barrel of over $30, are likely to remain on average above 30 p/therm, subject to seasonal variation.

As UK gas production declines, ILEX forecasts the overall supply/demand balance tightening until around 2007, when new gas import infrastructure comes online. Until then, there will continue to be significant risk in the traded gas market with prices remaining vulnerable to colder than average winters, any unexpected but sustained interruptions in supply from major offshore fields and/or delays in the new import routes.

However, given the Interconnectors ability to export, prices are unlikely to collapse when new import routes start bringing in abundant supplies.

ILEX has found no evidence of market abuse, noting that the UK has a highly liquid market with gas being traded around 14 times before it is delivered, making price manipulation difficult to achieve. Although market liquidity is not overall seen as a problem, the lack of truly speculative traders willing to go short in the market is of concern, as this appears to be contributing to the upward pressure on prices, with no counterbalancing downward pressure.

Indeed, ILEX claims that market sentiment reflecting traders' fears of being caught short this winter may account for the difference between its forecast of around 45 p/therm and the forward curve of over 50 p/therm.

Mike Tholen, UKOOA's Economic and Commercial Director, said: 'The UK has the most liberal, deregulated gas market in Europe in which gas prices are fully exposed to economic forces. Market liberalisation has attracted substantial new investment to ensure the UK's long-term security of supply. After a sustained period of low prices in the 1990s, gas prices have been driven upwards on the back of rising oil price and market sentiment.'

'While gas prices should benefit from increased liberalisation in the European market, we endorse the report's findings which show that oil price is likely to continue to influence longer-term pricing. It should be noted that, after removing the effects of general inflation, gas prices today are no higher than they were in 1990 and lower than they were in the mid 1980s.'

New fuel cell system for US market

IdaTech has unveiled a scalable 100 W to 500 W portable fuel cell system prototype soon to be introduced to the US market. The liquid fuel system with onboard reformer will be delivered to the US Army for use as a field battery charger in order to help solve the traditional logistical problem of getting power to troops in the field. The entire fuel cell system, including reformer and hydrogen purification module is about the size of a large lunch box, measuring about 12 x 8 x 6 inches. Its fuel is a prepackaged methanol-water mixture, which provides a highly compact and long lasting source of power.

'This new system represents a dramatic step forward in simplification, power density increases, cost reduction and portability,' said Claude Duss, IdaTech President and Chief Executive Officer. 'While the first unit is designed as an Army battery charging solution, it has the potential to open a new line of fuel cell products for IdaTech. We think this is another industry-leading move that will set the standard in small-scale fuel cell commercialisation.'

UK's largest green electricity contract

BT has signed what is claimed to be the UK's largest green electricity contract – for 2,1 TWh, which will cover almost all of BT's UK demand over three years – with RWE npower and Centrica. Although the deal represents an important step forward and a strong piece of PR for the environmental lobby, recent research from analyst Datamonitor indicates that just 15% of industrial and commercial companies have a set target for procuring green energy.

'BT has an impressive history in the area of environmental responsibility, having reduced energy related carbon dioxide emissions by 80% since 1991 through investment in energy management and more energy efficient equipment,' comments Datamonitor. 'The contracts secured with RWE npower and Centrica, for 1TWh of renewable power and 1.1TWh of energy from CHP (combined heat & power), will see a further reduction of 325,000 tonnes of CO_2 emissions per year – the equivalent of taking 100,000 cars off the road.'

'The agreement is certainly a landmark deal and represents a powerful PR opportunity for both BT and the wider green lobby. However, the contracts do not mean that the amount of green power generation in the UK will see a corresponding increase. Although RWE npower has some small interests in wind and hydropower, together with CHP these sources still accounted for less than 10% of its 2003 production. Centrica currently has no renewable generation, although it has committed £750mn to new renewable projects over the next three years.'

'This means that in reality the companies, particularly Centrica, will be sourcing the power through the use of renewables obligation certificates (ROCs), which allow suppliers to purchase green electricity produced by renewable generators through a traded system. As a result, there are no guarantees that the BT contract will increase the total renewable generation capacity of the UK as a whole, although it is likely to drive further liquidity in ROC trading.'

However, despite this positive news for advocates of renewable energy, recent research indicates that British companies still have a long way to go to emulate BT's achievements in this area. During July and August this year, Datamonitor completed in-depth interviews with senior energy buyers at over 1,500 industrial and commercial companies spending over £20,000 per year on power from around the UK. As part of the study, respondents were questioned on attitudes to green energy.

Just 15% of those questioned stated that their company has a target for procuring energy from green sources, with only 3% making this target public and 12% keeping it as an internal objective. 'In an era in which corporate responsibility is becoming an increasing priority, particularly for those companies with established B2C relationships, these figures are surprising. Of those that do have any sort of target, 27% are aiming for 6–10% of power to come from renewable sources, and 14% for between 0–5%. Around 1 in 10 of these respondents are aiming to source all their energy from green sources,' comments Datamonitor.

'Of those that do have a green energy target, external or internal, only 59% of them are currently sourcing a proportion of their energy needs from green sources. This illustrates the fact that even for those who have a green target, four out of 10 have yet to actually start sourcing this power.'

Shell completes year-long GTL fuel trial

Shell has announced the results of a year-long gas-to-liquids (GTL) fuel trial involving six trucks operating on conventional engines provided by California-based bottled water distributor, Yosemite Waters. The results show that GTL fuel reduced all regulated emissions, with a cut in oxides of nitrogen (NOx) and particulate matter (PM) emissions by 16% and 23% respectively during a New York City Bus drive (NYCB) cycle without a particulate filter. The NYCB cycle is a standard set of simulated driving conditions used by researchers to test emissions. With a catalysed diesel particulate filter, NOx and PM emissions were further reduced, with overall reductions of 20% and 97% respectively.

GTL fuel, a colourless and odourless synthetic fuel made from natural gas, with virtually no sulphur and aromatics, is expected to play a key role in the transition to renewable fuels and advanced engine designs. 'These trial results provide important data to legislators, commercial users and the public and will allow them to make better decisions about air quality,' said Jack Jacometti, Vice President Global GTL Development.

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cash and stocks. The acquisition includes the network of Kaneb Terminals, formerly the ST Services sites in the US, UK and Australia/New Zealand and the Statia Terminals facilities in Canada and Netherlands Antilles. Once finalised, Valero will operate 101 terminals around the world and will be the largest terminal operator in the US.

***Arnold Schwarzenegger, the Governor** of California, has officially dedicated the state's first retail-designed hydrogen demonstration refuelling station, at a BP-branded site at Los Angeles International Airport. The station has been developed in partnership with Praxair, South Coast Air Quality Management District and Los Angeles World Airport and will provide hydrogen for five DaimlerChrysler fuel cell cars.*

Middle East

***Foster Wheeler Energy has been** awarded a project management services contract by Saudi International Petrochemical Company (Sipchem) for its acetyls complex to be built at Jubail Industrial City, Saudi Arabia. The complex will produce 460,000 t/y of acetic acid and 300,000 t/y of vinyl acetate monomer. Phase I of the complex, comprising methanol and butanediol plants, is currently under construction. The facility is expected to start up in 2008.*

Asia-Pacific

***Sinopec is reported to be buying** chemical plants and service stations from its parent, China Petrochemical, for $553mn in cash and assets. As part of the deal, Sinopec will sell its unprofitable oilfield services to the parent company.*

***Vopak is to enter into a 50:50 joint** venture agreement with Cosco Logistics to form a chemical logistics services company in China. Under the agreement, Vopak will provide access to its five terminals along the Chinese coast, with a total storage capacity of over 600,000 cm, and bring its current land-based chemical logistics services activities into the new joint venture company. Cosco Logistics will make available the use of its eight main warehouses, with a total capacity of 450,000 sq metres, as well as its 1,300 trucks and 13 barges for dangerous goods for feeder services in the Yangtze River and Pearl River Delta.*

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Latin America

***Total has finalised an agreement to** acquire 100 service stations on the island of Puerto Rico. The GPR- and CITGO-branded retail outlets are spread widely across this island and they will be branded in the Total colours by the end of 2005. With this agreement Total has acquired 6% of the retail market. In spring 2004, Total set up a distribution network in Jamaica, an addition to its presence in the French Caribbean islands.*

Africa

***The Egyptian government is reportedly** planning to build a new 650,000 kW power plant in the Red Sea resort of Sharm el Sheikh.*

***On 27 May 2003 BG Group and the** Tunisian government entered into a memorandum of understanding for the development of a 500-MW CCGT (combined cycle gas turbine) power plant. BG reports that discussions on this project have not yet been concluded and the group does not expect the Barca project to contribute to its 2006 power target as originally planned. As a result, BG Group has revised its 2006 power target to 2.8 GW from 3.3 GW.*

***More than half of all petrol sold in** sub-Saharan Africa is now unleaded, says the UN Environment Programme (UNEP), which wants leaded fuels phased-out in the region by 2006. Kenya has announced plans to switch to fully unleaded petrol by January 1 2006, reports* Keith Nuthall.

Imperial invests in Canadian refineries

Imperial Oil has unveiled plans to invest about $500mn to produce ultra low-sulphur diesel at its refineries across Canada. Work to reduce sulphur levels in diesel fuel for on-road vehicles by almost 95% has already begun at Imperial Oil's Strathcona refinery in Alberta, its Sarnia and Nanticoke refineries in Ontario, and its Dartmouth refinery in Nova Scotia.

The company says that it plans to be producing ultra low-sulphur diesel at all is refineries within the next two years, which, in combination with 2007 model vehicle engines, will 'reduce smog causing nitrogen oxides and particulate matter emissions from diesel-powered vehicles by almost 90%.'

Government regulations introduced in February 2001 call for the sulphur levels in on-road diesel to be reduced to 15 ppm by 1 June 2006. Imperial Oil will be meeting this new requirement well in time for the introduction of 2007 model vehicles whose new engine designs will benefit from ultra low-sulphur diesel.

Shell and Sol Group sign oil products deal

Shell and the Sol Group (Sol), a petroleum affiliate of the Interamericana Trading Corporation (ITC), are to sign a sale and purchase agreement and a trade mark licence agreement relating to the divestment of Shell's oil products businesses in Barbados, St Lucia, Netherlands Antilles, St Kitts & Nevis, British Virgin Islands, Anguilla, Grenada, St Vincent, Antigua, Dominica, Belize, Guyana and Suriname, excluding the aviation business.

The agreements relate to Shell's retail, commercial, local marine and LPG businesses, and includes a network of 111 fuel retail service stations and 30 distribution depots geographically spread across the region. The sale is subject to regulatory approval and completion is expected early in 2005.

Sol will continue to use the Shell brand under a trade mark licence agreement and act as the sole distributor of Shell's fuels and lubricants in this region. It will also act as an agent and partner on behalf of Shell Aviation, facilitating further development of aviation business opportunities in the region.

Sulphur-free fuels from Statoil

Sulphur-free automotive fuels are now being offered on the Norwegian market by Statoil. The group's Mongstad refinery near Bergen is producing both petrol and diesel oil with less than 0.001% sulphur – defined by international standards as free of the chemical. This follows the investment of more than NKr1bn at the plant. All of Statoil's service stations are due to be receiving the sulphur-free fuels by the New Year.

The European Union has decreed that these products must be available to the market from 2005, and must be the only form on sale from 2009. This new standard will reduce annual sulphur emissions from automotive fuels in Norway by more than 120 tonnes, corresponding to 240 tonnes of sulphur dioxide.

UK Deliveries into Consumption (tonnes)

Products	†Sept 2003	†Sept 2004	†Jan–Sept 2003	†Jan–Sept 2004	% Change
Naphtha/LDF	191,499	136,665	1,692,912	1,670,991	–1
ATF – Kerosene	922,561	966,856	7,582,572	7,964,891	5
Petrol	–	–	–	–	–
of which unleaded	1,639,714	1,510,712	14,086,703	14,264,821	1
of which Super unleaded	70,125	51,706	612,042	629,548	3
ULSP (ultra low sulphur petrol)	1,569,589	1,459,006	13,474,661	13,635,273	1
Lead Replacement Petrol (LRP)	13,437	126,807	160,028	175,511	10
Burning Oil	283,280	279,403	3,002,813	3,075,656	2
Automotive Diesel	1,489,523	1,560,616	12,680,405	14,052,065	11
Gas/Diesel Oil	592,887	538,327	4,678,957	4,729,555	1
Fuel Oil	152,788	263,454	1,724,087	1,873,423	9
Lubricating Oil	69,397	52,535	628,943	556,150	–12
Other Products	531,217	807,578	5,938,681	7,449,319	25
Total above	5,886,303	6,142,953	52,402,969	55,712,381	6
Refinery Consumption	277,445	436,473	3,432,245	4,001,018	17
Total all products	6,163,748	6,579,426	55,835,214	59,236,326	6

† Revised with adjustments

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

Seeking new frontiers

*Dr Marita Bradshaw** **of Geoscience Australia provides an overview of Australia's major discoveries to date and focuses on the search for new hydrocarbon plays and investment opportunities for the international oil and gas industry.**

Geoscience Australia's programme of data acquisition in the deepwater frontier basins of the south-west margin began in February 2004 with a marine sampling survey aboard the national research facility *RV Southern Surveyor*

The reputation of Australia's North West Shelf as a world class gas province was confirmed in 2000 by the discovery of two super giant gas accumulations – Jansz in the Carnarvon Basin, and the Brewster-Ichthys complex in the Browse Basin. With 20tn cf of reserves, the Jansz accumulation is the largest gas field yet found in Australia and proves up a new play type. The gas is reservoired in Late Jurassic channel sands rather than in a Triassic fault block – the usual habitat of multi-tn cf fields on the North West Shelf.

More large gas discoveries remain to be made as demonstrated by the recent success at Wheatstone-1 drilled by ChevronTexaco in August 2004.

Accelerating gas development

LNG export markets for Australian gas are established and growing in the Asia-Pacific region, particularly in Japan, Korea and China. By September 2004 the North West Shelf joint venture's fourth production train was in operation and there are plans for a fifth train in 2005. Construction has commenced on the Darwin LNG project which will develop the Bayu/Undan gas/condensate field in the Timor Sea.

Other giant gas fields being considered for development to supply the export market are Greater Gorgon and Scarborough in the Carnarvon Basin, Scott Reef and Brecknock in the Browse Basin, and Greater Sunrise and Evans Shoal in the Bonaparte Basin.

New domestic gas developments are well advanced in south-eastern Australia, in the Bass and Otway Basins. The BassGas project, which will bring gas ashore from the Yolla and White Ibis fields, is under construction, as is the Minerva development. In northern Australia, the Blacktip gas field in the Bonaparte Basin is slated for development with the building of a pipeline across the Northern Territory to the Gove alumina refinery.

New oil discoveries

In addition to the major gas discoveries, there has also been a string of significant new oil discoveries. Inboard of the giant gas fields in the Carnarvon Basin, the oil trend has been extended both north and south by recent finds. At the northern end, in the Dampier Sub-basin, is the Exeter field discovered in 2002, which together with the 1998 Mutineer discovery holds some 100mn barrels of oil that is expected to be brought into production in 2005. At the southern end of the oil trend, in the Exmouth Sub-basin, a number of discoveries over the past five years – including Vincent, Enfield, Laverda, Stybarrow, Ravensworth, Crosby and

Stickle – add up to form a significant new oil province with several hundred million barrels of reserves that are expected to be in production by 2006.

There has also been success in other areas beyond the North West Shelf. The Cliff Head discovery, drilled in December 2001, is the first major oil find in the offshore Perth Basin, where there has also been recent onshore oil and gas discoveries. Meanwhile, in eastern Australia's Bass Strait, development drilling of the Yolla gas field intersected an oil leg. A number of new onshore oil discoveries have also been made in the Cooper Basin located in central Australia.

New government initiatives

With these discoveries Australia's gas reserves are at an all time high and continuing to climb steeply. However, oil reserves are in decline. The historical trend for oil production shows a shift from the Gippsland Basin to the North West Shelf, and from sustained production over decades from few giant oil fields to many small fields of much shorter life. However, the continent is vastly under-explored, only 8,000 wells have been drilled and many offshore basins have never been tested. The big fields in a petroleum province are usually found first and Australia's best chance of adding major new oil reserves is to find a new petroleum province – and the deepwater frontier basins are a key place to look.

To stimulate this search a number of key government policy decisions have been made with the aim of encouraging exploration investment in Australia. These include the decision in 2001 to facilitate access to government spatial data at the cost of transfer, or free via the web. An example is Geoscience Australia's online geological provinces database (**www.ga.gov.au/oracle/provinces**) which describes a multitude of offshore basins and sub-basins (144 at last count) and is also linked to detailed well and other data. In 2003 the Australian Government announced the injection of an additional A$61mn into Geoscience Australia's petroleum programme for new data acquisition and for data preservation and archiving. This boost was followed in the 2004 federal budget with the introduction of tax incentives for exploration in frontier areas.

Geoscience Australia developed a portfolio of potential projects based on integrated programmes of seismic acquisition, geological sampling and oil seep detection. One of the potentially petroliferous frontier provinces considered for new data acquisition was the Bremer Sub-basin in deepwater at the western end of the Great Australian Bight. Reprocessed reconnaissance seismic shows a thick and well structured Mesozoic section. The Mentelle Basin is another significant Mesozoic depocentre in deepwater between the Naturaliste Plateau and south-western Australia.

Dredging of sub-marine canyons recovered tonnes of rocks from the previously unknown sedimentary section of the Denmark and Bremer Sub-basins, offshore between Albany and Esperance

The Lord Howe Rise is also part of the portfolio. It is a submerged ribbon continent now lying in the Tasman Sea between Australia, New Zealand and New Caledonia. Before seafloor spreading in the Late Cretaceous, this continental sliver was juxtaposed between the petroiferous basins of Bass Strait and New Zealand's petroleum producing Taranaki Basin. There are more than a dozen depocentres on the Lord Howe Rise that have the sufficient thickness of sediment to have generated hydrocarbons if organic rich facies are present.

To the south of Tasmania is another submerged landmass – the South Tasman Rise, which also contains thick depocentres that are prospective for petroleum. The Rise acted as a keel to Australia as it rifted away from Antarctica, maintaining restricted marine environments to its west through the Late Cretaceous and Paleogene. Conditions may have been conducive to the deposition of oil prone source rocks in this oceanic cul-de-sac.

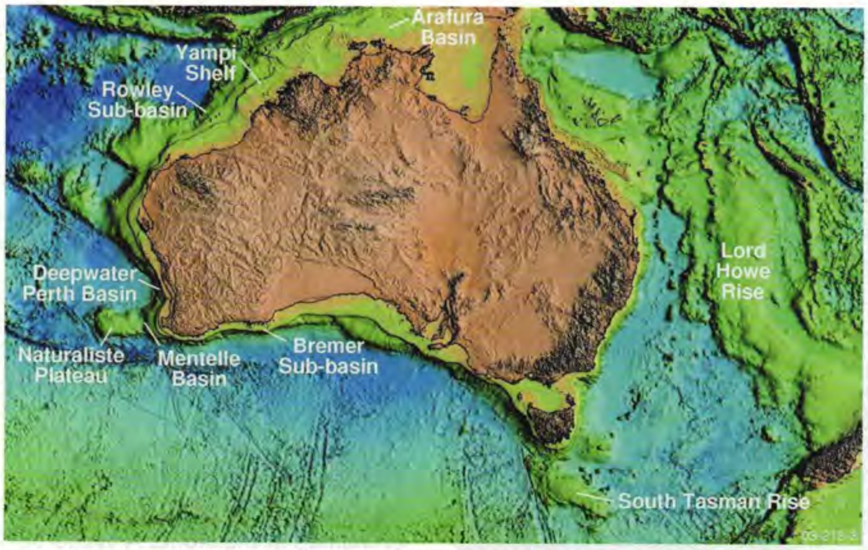
Following a round of industry consultation, the immediate priority areas for new data acquisition identified were the shallow-water Arafura Basin in northern Australia, and the deepwater frontier basins of the South West Margin. Validation of remote sensing as a reconnaissance technique for detecting hydrocarbon seepage in the vast offshore areas was also seen as an important part of the new programme.

In March 2004 a survey was under-

Country/Field	Operator	Oil or gas output	Start-up date	Oil res. (mn b)	Gas res. (bn cf)	Capex ($mn)	Production system
AUSTRALIA							
Angel	Woodside	gas/cond	2010		1,800		platform
Bambra	Apache	gas/cond	2004	0.7	30		wellhead plat via Harriet
Blacktip (Bonaparte Gulf)	Woodside	gas	2007		1,100		potential 2.53mn cm/d
Brecknock/Scott Reef	Woodside	gas/cond	2010+	228	18,400		poss LNG development
Chrysaor/Dionysus*	Wapet	gas	2010/12	75 (cond)	3,988	150	*part of A$10 bn project
Cliff Head	Roc Oil	oil	2005	20–30			
Crosby (Exmouth)	BHP Billiton	oil	2006	112ft column			
Dixon/Castor	Woodside	gas/cond	2005/10				FPSO, gas to Echo-Yodel
Dockrell/Keast	Woodside	gas/cnd/oil	2005/10				to Echo-Yodel or Goodwyn
East Pilchard	Esso Australia/BHP	gas	2005+				
Echo/Yodel	Woodside	gas/cond	mid-2002	37(cond)	400	200	2 subsea via Goodwyn A
Enfield (WA-271-P)	Woodside	oil/gas	4Q2006	125–146		1,480	FPSO (900,000 b) 100,000 b/d
Evans Shoal	Shell Australia	gas	2005/09		10,500		poss supply to Darwin LNG, 7.5mn t/y?
Geryon*	ChevronTexaco	gas		103 (cond)	3,320		
Gypsy/Rose/Lee	Apache	oil/gas	2002/3	7	150		wellh'd plat to Varanus Islnd
Golden Beach	Santos	gas	2005+		50		
Gorgon*	ChevronTexaco	gas	2012	316 (cond)	18,379		poss 6mn t/y LNG plant
Iago*	ChevronTexaco			89 (cond)	977		
John Brookes	ExxonMobil	gas/cond	under eval		450		
Kipper (Gippsl'nd Basin)	ExxonMobil	oil/gas	2006	13	575	263	
Laminaria Phase 2	Woodside	oil	2002	21		130	2 horiz wells. 65kb/d peak
Laverda	Woodside	oil	2006	56.3			via Enfield facils
Loxton Shoals/Sunrise/Troubador	Woodside	gas	2005/09		5,000		Darwin LNG, 7.5mn t/y?
Macedon/Pyrennes	BHP	gas	under eval				
Manta/Basker/Gummy	Woodside	oil/gas	2003/6	26	260		FPSO and subsea
Minerva/La Bella (Otway)	BHP	gas	2005	1	360		subsea or monotower
Monet (nr Varanus Island)	Apache	oil	2004				
Mutineer-Exeter (Cnvrn Basin)	Santos	oil/gas	mid-2005	100		283	Modec FPSO 100,000 b/d (07),3mn cf/d
Nappamerri trough	Santos	gas	end-2003				
Nasutus	Apache	oil	under eval				
Orthrus/Maenah*	ChevronTexaco	gas		31 (cond)	1,199		
Patricia Baleen (Bass St)	OMV	gas	2004?		70	52	subsea
Perseus/Athena	Woodside	gas/cond	1999 on		7,600		North Rankin and subsea
Petrel/Tern	Santos	gas	under eval		2,700		
Ramillies	BHP	oil	2002+	2			
Rankin-Sculptor	Woodside	gas/cond	2005-10				subsea to Echo-Yodel
Ravensworth (Exmouth)	BHP Billiton	oil/gas	2006	121ft column	26ft column		
Reindeer	Apache	gas	under eval		350		
Scarborough	ExxonMobil	gas	2010+		8,000	$4.7bn?	supply proposed LNG?
Searipple	Woodside	gas/cond	2005+		50		with Perseus via N Rankin
Sole (off Victoria)	Basin Oil (OMV)	gas	2005		277		2 subsea production wells
Spar*	Chevr/Tex/Ampol/Shell	gas	2012	11 (cond)	350		
Stickle		oil	2006				
Sybarrow (Exmouth Basin)	Woodside	oil	2006	50			
Tenacious	OMV	oil	under eval	5		42	tie-back to Jabiru
Tern/Petrel (B'nap'te Gulf)	Santos	gas	2008+		3,000		platform or FPS
Tidepole	Woodside	cond/gas	2013	14 cond	420		
Thylacine – Otway Gas	Woodside	gas	mid-2006		436	170	wellh'd plat + 5 subsea 60PJ/y
Geographe – Otway Gas	Woodside	gas	2006		364	170	3 subsea manifold part of above
Urania*	ChevronTexaco	gas		8 (cond)	266		
Vincent (WA-271-P)	Woodside	oil	2006+	117.4			via Enfield facils
West Tyral Rocks*	Wapet	gas	2010	98 (cond)	3,513		
White Ibis (Bass Gas project)	Origin Energy (ex Boral)	gas	2005				
Wilcox	Woodside	gas/cond	2010		300		to Goodwyn or Echo-Yodel
Yolla (Bass Gas project)	Origin Energy (ex Boral)	oil/gas/cnd	2005	45 cond	300	240	platform 49mn cf/d,5kb/d 49mn cf/d,5kb/d
Woolybutt	Eni	oil	Mar-03	25		70	2 subsea to FPSO 40,000 b/d
KEY DISCOVERIES							
Lynx/Vega	Woodside	gas					
Casino (Otway Basin)	Santos	gas			300		
Jacaranda (Otway Basin)	Boral Energy	oil					
Tregony (PEP 153)	Santos	gas					potential 10–15 mn cf/d
Io/Jansz*	ExxonMobil	gas		120 (cond)	20,000		joint development Gorgon
Titanichthys	Inspex Browse	gas/cond		700mn boe			
Gorgonichthys	Inspex Browse	gas/cond		2,339mn boe			
Brecknock South	Woodside	gas/cond		88	3900		
Wheatstone-1	ChevronTexaco	gas			test 54mn cf/d		
TIMOR GAP-ZOCA							
Greater Sunrise**	Shell	cond/gas	2006/7?	300	9,160		with Bayu Undan/float LNG
Laminaria East	BHP	oil					close to Buffalo field
Bayu/Undan	Phillips	cond/gas	Feb-04	404		1,696	3 platforms, Ph1 liquids
Bayu/Undan	Phillips	gas/LNG	2H2006		3,400		phase 2 LNG
Jahal	BHP	oil					
NEW ZEALAND							
Kahili	Indo-Pacific	oil/gas	mid-2004				
Kauhauroa	Westech	gas	uncommercial at present			170	
Kauri	Swift Energy	oil/gas/cond	2004				
Kupe	Origin Energy (ex Boral)	gas/oil	mid-2007	16	264	250	platform 20bn cf/y, 1.6mn b/y
Maari	OMV New Zealand	oil	2006	25		170-300	FPSO + subsea initial 30,000 b/d
Pohokura	Shell	gas/cond	Jun-06	43 (cond)	700	170-300	6 ss wells to NNM plat +3ER initial 50bn cf/y
Rimu	Swift Energy	oil/cond	1Q2002	27 (boe)			

*Greater Gorgon comprises 850mn barrels of condensates and 52tn cf of gas in 10 accumulations **Greater Sunrise comprises Sunrise, Sunset and Troubadour

Table 1: Planned field developments in Australasia



Map of Australian options for new data acquisition

taken in the natural laboratory of the Yampi Shelf, on the North West Shelf – an area of known hydrocarbon seepage with a good coverage of multiple datasets, including Synthetic Aperture Radar (SAR), Airborne Laser Fluorescence (ALF), Landsat, 'sniffer' water column geochemistry and 3D seismic. Active gas seepage was found, imaged, and tied back to its expression on seismic and bathymetric records. In April 2005, the tools and techniques developed and tested on the Yampi Shelf will be applied in the Arafura Basin, at a number of sites where remote sensing and seismic data indicate the possible occurrence of natural hydrocarbon seepage.

Geoscience Australia's programme of data acquisition in the deepwater frontier basins of the south-west margin began in February 2004 with a marine sampling survey aboard the national research facility *RV Southern Surveyor.* Dredging of sub-marine canyons recovered tonnes of rocks from the previously unknown sedimentary section of the Denmark and Bremer Sub-basins, offshore between Albany and Esperance Analysis of the samples has identified reservoir quality sandstones and potential oil-prone Jurassic and Early Cretaceous source rocks.

The most recent seismic coverage of the Bremer is a 1974 survey shot by Esso. The vintage and limited extent of this data only provides glimpses into the sub-surface geology and does not allow a full understanding of the area's hydrocarbon potential. New seismic data now being acquired with Veritas' *Pacific Sword* will better define the extent, thickness and stratigraphy of the basin fill and may identify potentially prospective structures. This data will be available from Geoscience Australia to explorers at the cost of transfer. The Bremer is, however, only one of several potentially prospective basins along the south-west margin and the seismic survey has also collected data in the Mentelle and deepwater Perth Basins.

These first surveys in the Arafura Sea and in the frontier basins of the south-west margin are the beginning of a four-year programme aimed at developing many new investment opportunities and presenting them to explorers in the annual release of offshore petroleum acreage.

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Full steam ahead

Exploration for oil and gas in New Zealand has entered a period of high growth while the development of a number of new projects is in full swing. *Lindsay Clark* reports.

Two gas and two oil field developments soon to be underway offshore from Mount Taranaki

The recent growth in exploration has seen more international companies entering New Zealand, encouraged by favourable prospectivity, an attractive investment climate, large future demand for domestic natural gas and steadily rising local gas prices, and, of course, higher world oil prices. The country offers a wide range of E&P opportunities, ranging from large deepwater prospects to shallow onshore oil targets and coalbed methane prospects.

New Zealand sits on a large continental shelf – an underwater 'mini-continent' of about 6mn sq km – over 20 times as large as the land. This continental shelf stretches from sub-tropical to sub-Antarctic waters – as long as the distance from northern Norway to Gibraltar. Within New Zealand's submarine continent are a large number of sedimentary basins. Six of these have proven petroleum systems, a couple of others have strong hydrocarbon potential, while the rest are essentially unexplored. The Taranaki Basin on the west coast of the North Island is the only basin with commercial production so far, and it remains the focus of the recent expansion in exploration activities. Current exploration permits have grown to 100, up from 66 in September 2002. More than half of the permits are issued for Taranaki, with offshore acreage attracting strong recent interest.

The total number of wells drilled in New Zealand by the close of 2004 is expected to reach almost 30 – the most to have been drilled in any year since exploration began.

Rising energy demand

New Zealand has one of the most open economies in the world. A World Bank survey recently rated the country as the easiest place in the world to do business. The *Doing Business in 2005* report highlighted the ease of registering property and getting credit as two aspects that help to give New Zealand the highest ranking ahead of the US, Singapore, Hong Kong and Australia.

The country is currently experiencing its strongest and most consistent period of economic growth for 40 years. Indeed, economic growth has exceeded forecast growth over the past two years (see **Table 1**). One of the results of this growth has been a rising demand for energy, with electricity consumption growing by 5% in the year to March 2003 and a long-term average growth of 2% a year. The increased demand for electricity in recent years has largely been met by greater use of gas-fired power stations.

While New Zealand still produces over 60% of its power needs from hydroelectric stations, gas now accounts for between 22% to 25% of the country's electricity supply and is an important swing producer of power when low rainfall affects hydro lake output and at times of high seasonal demand. Electricity generation now takes half of all gas produced. (See **Figure 1**.)

Increasing demand for gas has seen wellhead gas prices respond accordingly. Over the past three years prices have sharply increased from US$1.20/1,000 cf to about US$4. Because all discovered reserves will not replace producing reserves, it is likely gas prices will remain high.

The supply of gas has been affected by an earlier than expected decline in reserves from the offshore Maui gas field, which currently supplies 65% of total gas production. The decline so far has been absorbed by the winding back of production at the largest of two methanol plants in Taranaki. These plants were originally built in the 1980s to absorb excess gas from the 3.5tn cf Maui field and are now owned by the world's biggest methanol producer – Methanex.

With the era of cheap Maui gas drawing to a close and energy forecasts all showing a growing disparity between rising gas demand and post-Maui gas supply, industry and government are focusing attention on how to fill the energy gap.

Government incentives

The New Zealand government introduced a package of measures in June 2004 to provide investment incentives aimed at accelerating exploration activities to find new gas reserves. For a five-year period royalties on gas discoveries will be reduced from 5% to 1%, and a deduction of exploration and prospecting costs from royalties will be allowed.

The package will also remove a tax obstacle on offshore drilling rigs and seismic ships, which previously discouraged offshore operators from keeping the vessels in New Zealand waters for longer than six months at a time. An extra NZ$15mn (US$11mn) has also been added for government-led seismic mapping and promotion of New Zealand as a petroleum prospecting destination.

Downstream consumers of gas are giving strong indications that they want to acquire more natural gas in the future. Two electricity generation companies which are major users of gas for power – Contact Energy and Genesis Energy – have both begun investments in upstream projects. Contact Energy has taken out an offshore Taranaki exploration permit and has indicated its preference for acquiring local supplies of gas in the future, rather than looking to importing LNG.

Genesis Energy operates New Zealand's largest thermal power station, which can run on coal or gas. The company has switched to run largely on coal over the past two years, but it is also installing over 400 MW of new gas-fired plant alongside the older 1,000-MW station at Huntly, south of Auckland. The company has underwritten the cost of a deep gas well being drilled in onshore Taranaki towards the end of 2004 and has a substantial interest in the offshore Kupe gas field, which is expected to come into production in the next three years.

Methanex, which has been the largest single downstream user of gas, also funded its first deep gas well in September 2004 in onshore Taranaki. The first of these wells, Radnor-1, test flowed at over 6mn cf/d. Methanex has priority entitlement to the gas produced.

A number of other explorers plan to target other onshore gas prospects which were previously uneconomic to

Key indicators	2003	2004	2005 forecast
GDP growth	4.4%	3.6%	4%
Interest (90-day bills)	5.9%	5.3%	6.25%
Inflation	2.5%	3%	3%
Unemployment	4.9%	4.3%	4%

Source: Reserve Bank of NZ, September 2004

Table 1: New Zealand's strong economic growth

Name	Location	Size (estimated reserves)	Final investment decision	Date onstream
Pohokura	Offshore Taranaki	700bn cf gas, 43mn barrels condensate	Approved July 2004	June 2006
Kauri	Onshore Taranaki	oil, gas, condensate	Mining permit applied for	early 2005
Kupe	Offshore Taranaki	264bn cf gas, 16mn barrels oil	June 2005	mid-2007
Maari	Offshore Taranaki	50mn barrels oil	December 2004	Likely 2006
Tui area	Offshore Taranaki	30bn barrels oil	June 2005	mid-2006

Table 2: Planned oil and gas field developments in New Zealand

Higher gas prices stimulate more deep gas wells

develop when abundant cheap Maui gas was available.

Fields under development

The largest and most significant new field development currently underway is the Pohokura gas-condensate project in offshore Taranaki near New Plymouth (see **Table 2**). The Pohokura field contains reserves of 700bn cf of natural gas and 43mn/b of condensate. Partners in the petroleum mining permit PMP 38154, issued in October 2004 for a 32-year period, are Shell New Zealand (48%), Vienna-based OMV New Zealand (26%) and Wellington-based Todd Energy (26%).

First gas is expected in mid-2006, with an initial production of approximately 50bn cf/y – representing approximately 25% of New Zealand's total annual gas production. In addition, 3mn/b of condensate are initially expected a year.

Pohokura will have six offshore development wells linked to a single unmanned offshore platform, plus three extended reach wells drilled from onshore, all feeding a new production station close to major gas and oil pipelines. Onshore construction is due to begin in early 2005, with offshore activity starting in 3Q2005.

A second offshore gas-condensate field – Kupe – off the south Taranaki coast, is also being developed. The field contains reserves of 264bn cf of natural gas and 16mn barrels of condensate. Kupe operator Origin Energy says the field will produce approximately 20bn cf/y of sales gas and 1.6mn b/y of light oil when it begins production in 2Q2007. The final investment decision is due about June 2005.

The initial engineering design contract for the development of Kupe has been awarded to the Australian-based company Worley. Key parts of the project will be an unmanned offshore platform, a subsea pipeline to deliver the raw natural gas and light oil to shore, and a new onshore or upgraded existing production station.

An offshore oil development – Maari – to the south of the Maui field, is based mainly on the relatively shallow Moki Formation. Maari contains about 50mn/b of oil and is operated by OMV. The oil would be accessed through an FPSO vessel.

Onshore, the largest project being developed is the Kauri field on the South Taranaki coast, operated by Houston-based Swift Energy. The Kauri structure contains oil, gas and condensate at a number of levels in a number of structures. Kauri adjoins the Rimu field, which Swift Energy also discovered and brought into production in 2002. Both fields will feed the company's Rimu production station.

Swift Energy is making extensive use of hydraulic fracture stimulation in its wells and has achieved three to five-fold increases in deliverability from pre- to post- 'fraccing'. The company is also making use of artificial lift for some shallow oil wells in the Kauri field.

A small onshore Taranaki gas-condensate field – Kahili – operated by Austral Pacific Energy, was brought into production in September 2004.

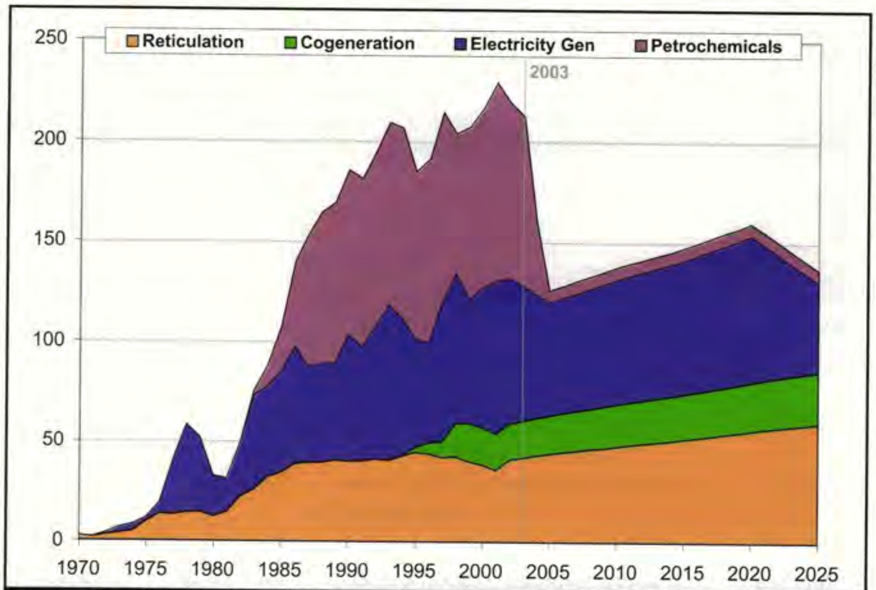

Figure 1: NZ gas demand expands for higher price uses

Offshore oil discoveries

Perhaps the most encouraging discoveries recently have been the finding of three adjacent oil fields – Tui, Amokura and Pateke – to the north-west of the Maui field. This indicates that there is an oil-bearing fairway in the large Western Platform area of the offshore Taranaki Basin. Early planning indicates the Tui area discoveries have joint reserves of between 20-30bn barrels of oil and could be brought onstream using an FPSO vessel by 2006. All three discoveries were in the Kapuni F sands, a geological formation which also contained New Zealand's largest crude oil discovery, at the Maui B field just to the south. The crude oil part of Maui B is nearing depletion.

Intensive exploration of the 22 offshore Taranaki permits is expected over the next few years, including in the permits held by Houston-based Pogo Producing, which plans an extensive 3D seismic acquisition programme in its three northern Taranaki permits.

Large permits tender for 2005

The government agency controlling New Zealand's petroleum estate, the Crown Minerals group of the Ministry of Economic Development, is planning a large public tender for petroleum permits in at least three basins in 2005. Because of recent interest in New Zealand exploration from US explorers, a multi-basin permit tender is expected to be more attractive to larger companies. Full details and timing for the tender have yet to be announced.

One basin which will definitely be included in the tender is offshore Northland, north of Taranaki on the west coast of the North Island. Northland is the closest basin to Auckland, New Zealand's largest centre of population. Five offshore Northland blocks will be included.

An offshore gas-condensate discovery – Karewa – was made in 2003 on the southern edge of the Northland blocks. Operator Todd Energy has acquired more acreage nearby, containing similar closures.

Recent geological studies based on seismic reprocessing and a deepwater well have revealed new insights into the Northland Basin and petroleum potential has now been upgraded. The Northland Basin is considered to be part of the Greater Taranaki Basin, with many features in common with surrounding areas. Six petroleum systems are known to be present in the Northland region and two are known to be active. Jurassic sedimentary rocks, not previously thought to exist in this area, are now considered to have petroleum potential.

The neighbouring Deepwater Taranaki Basin has also recently been shown to have a large delta, containing large volumes of petroleum source rocks of mainly late Cretaceous origin. Thick coal-measures, equivalent to the Rakopi Formation that is the main source of Taranaki petroleum, have been mapped over some 15,000 sq km. Thermal modelling indicated that the source rocks are generally mature. Wells have yet to be drilled in the delta sequences.

On the east coast of North Island many oil and gas seeps and strong shows of gas in each of the three offshore wells drilled continue to tantalise explorers. More work is underway, including government-funded seismic acquisition, to better understand how best to capture the hydrocarbons in the basin.

South Island first in 20 years

Off the east coast of South Island, in the Canterbury Basin, the first well to be drilled in 20 years is planned for the middle of 2005 by Perth-based Tap Oil. Tap is targetting a structure updip of a previously drilled well, Galleon-1, from which BP (in the 1980s) flowed gas at 10mn cf/d and condensate at the high rate of 2,240 b/d. However, the well was regarded as uncommercial at the time. If a similar condensate-rich discovery is found, Tap plans to initially strip the condensate and reinject the gas until a gas market and pipeline structure is developed in South Island.

At the far south of South Island, the Great South Basin is regarded as one of New Zealand's most prospective areas for both oil and gas. Only Taranaki Basin has had more offshore wells drilled. Eight wells were drilled in the 1970s and 1980s, but since then the Great South Basin has largely been overlooked – until recently.

An active petroleum system in the Great South Basin was proved with these early wells. Recent geological analysis indicates very large quantities of source rock, with modelling indicating that 1,800bn barrels of oil and 180tn cf of gas have been expelled.

A number of very large structures, many not tested by earlier wells, are being targeted by Australian explorers Hardman Resources, Bounty Oil and Gas and Magellan Petroleum.

The technical characteristics of New Zealand's offshore basins offer explorers the chance to discover petroleum resources of significant size and value to have material impact.

For more details on New Zealand exploration see the Crown Minerals website: **www.crownminerals.govt.nz**

And the winners are...

Petroleum Review is pleased to announce the winners of the EI Awards 2004*

Award	Sponsored by	Winner
communication award	ABN Amro	IT Power
community initiative award	BG Group	npower
environment award	KPMG	Walsh Ecuador
innovation award	ExxonMobil	Halliburton Energy Services
outstanding individual achievement award	Norman Broadbent	Dr Wolfgang Schollnberger
safety award	Shell	BG Exploration and Production India
technology award	Eni	Shell UK
international platinum award	Total	Shell Exploration and Production

highly commended: BG Group

*Full details of the prize-winning projects will be reviewed in the January 2005 issue


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Basking in the sun

It might not quite have matched the highs of 1971, but the past year has been sensational for tanker owners. Demand has rocketed, rates have followed suit, and even scrap prices are at record levels.

The trading environment over the past year has been very helpful to tanker owners. It has been one of those periods they dream of, when booming freight rates and consistent demand help make up for all the lean years. They have been able to lock into good timecharters at firm rates. Asset players have found secondhand prices very attractive. And even shipbreaking has offered a profitable way out, with Indian breakers offering record prices for scrap steel.

There have been strong demand figures underpinning these trends. Most notable has been the continued rise in demand for crude oil and petroleum products in China, where imports were up by around 50% over last year in 1H2004. Recovering oil demand in the US, allied to the continued decline in domestic production of crude oil and restrictions on new refinery capacity, has ensured firm employment for tankers trading into North America. It is not just China and the US; the International Energy Agency (IEA) is forecasting that global oil demand will increase more rapidly in 4Q2004 than in any period over the past 10 years.

Indeed, it is not overstating matters to suggest that this year has seen a structural change in the nature of the oil trades to a degree that has not been witnessed since the 1970s. Much of this is down to the boom in oil demand in China that has followed the country's entry into the World Trade Organisation and the beginnings of deregulation in its oil industry. Existing participants in the tanker market can currently take advantage of the better earnings available until new tonnage arrives to even up the supply/demand balance. However, with Sinopec and PetroChina both investing in new refinery capacity to come onstream over the coming four years, Chinese crude oil imports are set to continue to rise rapidly over the near term and it will be some time before enough new tonnage can be added to the world fleet to cope with the additional demand.

In addition to these fundamental factors, the rising price of crude oil and petroleum products has made sure that demand for tanker capacity has remained high. At a time of rising prices, buyers and traders are keen to lift as much product as quickly as possible. This trend cooled off in the third quarter, as prices were thought to be peaking, and the number of very large crude carrier (VLCC) fixtures was down on the 2003 figures for both July and August.

The year in figures

As an indication of the state of the market, spot freight rates for VLCCs from the Middle East to the Far East rose from Worldscale* (W) 45 in August 2003 to W110 a year later. Rates for westbound cargoes were also up, with W100 quoted for Middle East to North West Europe and W95 for cargoes to the US Gulf. VLCC rates for West African liftings were also substantially higher, rising from W55 in August 2003 to W120 a year later for US delivery. (All freight rate indications from Lloyd's MIU.)

Spot rates for smaller tankers also improved, although not quite to such a great extent. Suezmax rates for West Africa to the US were up from W85 in August 2003 to W150 a year later; and North Sea liftings for US delivery were up from W75 to W177. The importance of US demand can be gauged from the more modest improvement in Mediterranean to UK/Continent rates, from W97 in August 2003 to W148 this year. Rates for Panamax tankers were around twice their year earlier levels, except intra-North West Europe where the improvement was more muted.

As is often the case, the impact on timecharter rates has been less marked, although even here the rise has been substantial. *Lloyd's Shipping Economist* quotes September rates of $55,000/d for 280,000 dwt VLCCs on 12-month charters, compared to $29,000/d a year earlier; daily rates for Suezmax tankers were up from $25,500 to $38,000; and for Aframax (105,000 dwt) from $19,500 to $30,000.

Another indicator of the health of the tanker market is the value placed on secondhand tonnage. This year has seen not only an increase in values generally, but also a tightening in the differential according to vessel age. For instance, a year ago a five-year-old VLCC was priced around $60.5mn and a similar, ten-year-old tanker was less than half that price at $24.3mn. By September 2004, the value of a five-year-old VLCC had risen by almost a third to $80mn, but the older ship had risen in price by nearly 150% to $59.5mn. As a result, whereas a year before the older ship was valued at 40% of the value of the newer vessel, by the end of the third quarter this year the figure had risen to 75%. (All price indications from BRL Consultants.)

This improvement in secondhand values reflects not only the absolute level of demand for tanker tonnage but also the difficulty owners are facing in getting new ships built and the prices that yards can command. Very few of the main shipbuilders have much capacity at present – there is intense competition for yard space from other sectors of the merchant marine, notably bulkers and LNG carriers, which are also enjoying times of plenty – and rising steel prices have also pushed up the cost of building new ships. According to *Lloyd's Shipping Economist*, a new 300,000 dwt VLCC will cost $93mn this year, as against $67.5mn only a year ago. Prices for smaller vessels have risen by a similar degree.

A fleet in demand

As well as rising demand for tanker tonnage, the past year has been characterised by continued tightness on the supply side. Lloyd's MIU data suggest that the active crude oil fleet – even allowing for the reactivation of laid-up vessels – increased only marginally over the year to September 2004, growing by 2.4% to 245.7mn dwt. Some growth was seen in all sectors of the fleet except for Panamax tankers (50,000–75,000 dwt), where the active fleet actually declined because of a high volume of scrapping.

This tightness does not look likely to ease in the near future. While the size of the orderbook has increased over the past year, from 43mn dwt to 50mn dwt, half of this capacity is not due to arrive in the fleet until 2006 or beyond. The situation is little different for product tankers. The product fleet currently stands at 47.6mn dwt, up by 5% compared to a year earlier and while the orderbook has increased significantly over the past 12 months to 17.9mn dwt, 6.6mn dwt of the existing fleet is already over 25 years of age. The product tanker fleet is likely to be hit severely next year when new restrictions on single-hull tankers are introduced.

At a meeting in December 2003, the IMO's Marine Environment Protection Committee (MEPC) adopted changes to the International Convention for the Prevention of Pollution from Ships (MARPOL) – under pressure in particular from the European Union – that will result in the accelerated retirement of single-hull tankers. The MEPC meeting amended Regulation 13G so that pre-MARPOL tankers due to be retired from service in 2007 will now reach the cut-off point next year. The final phase-out date for MARPOL tankers and those under the MARPOL size threshold has also been brought forward, from 2015 to 2010.

In addition, MEPC adopted a new Regulation 13H that will ban the carriage of heavy grade oils (most crude oils and fuel oils, together with bitumen, tar and their emulsions) in single-hull tankers from April 2005. Both regulations allow maritime administrations to issue permits for tankers with double bottoms or double sides that do not meet the criteria of double-hull vessels to continue to operate, but only under certain conditions and not beyond 25 years of age.

It has been anticipated that these new restrictions would place a great strain on the availability of tanker tonnage to meet world demand. In particular, exports from the Russian Federation and other former Soviet republics have traditionally utilised older tonnage; this was expected to present a problem since exports of Russian crude are being relied upon to ease the global tightness in oil supply. However, according to Intertanko, recent data suggest that exports from the Baltic and Black Seas are increasingly being carried in double-hull tankers. In the first quarter of this year, 95% of Russian oil exports from the Baltic were carried in double-hull vessels, not least because of actions by some EU member states to prevent single-hull ships from passing through their territorial waters.

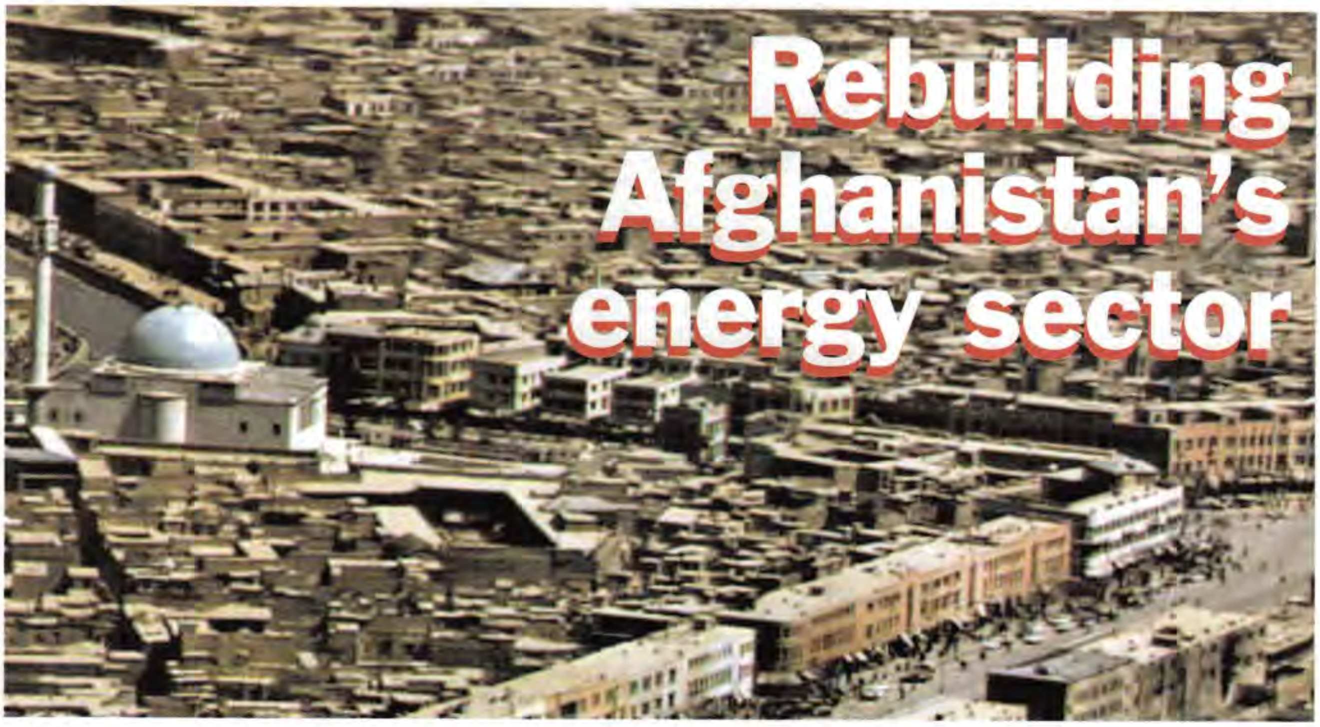
One problem that still remains to be resolved is whether the chemical tanker fleet will be able to meet demand after the 2005 and, more significantly, the 2010 deadlines. The projected capacity shortage is being compounded by a decision at the MEPC meeting in October this year to amend Annex II of MARPOL. This topic has been discussed for some 10 years now so the decision should come as no surprise; however, there is still some question as to whether there is sufficient IMO Type II capacity in the chemical tanker fleet to handle the large volumes of vegetable oils that will soon have to be carried in such vessels. Again, there is some flexibility built into the new provisions and it may well be that shipowners rise to the challenge. On the other hand, chemical tanker supply is also tight – not least because of the pull of cargo into China – and there is no spare capacity to shift easy chemicals into the more sophisticated end of the product tanker sector.

About time too?

These factors all seem to add up to a near-term outlook of continued high freight rates. US consultant Poten & Partners says that the dip in liftings in the third quarter of this year is just a temporary phenomenon and that seasonal factors will help trade volumes recover. Indeed, at the end of October VLCCs were being chartered on the spot market at rates as high as W275 for Korean discharge and one broker was quoted in *Lloyd's List* as saying that rates could hit W300 or even W350 over the winter.

Tanker owners would say that it is about time that they are being paid well for the services they provide and that charterers have had things too easy for too long. If they are going to be able to replace and renew the tanker fleet in the way that charterers and regulators are demanding, they will certainly need the extra revenues the market is currently providing, given the high costs of building new tankers at the moment.

**W=Worldscale – a rating system that allows charterers and owners to compare rates on different routes. Every year the Worldscale Committee publishes a comprehensive list of what W100 is in $/t for every conceivable journey around the world. W45=45% of the W100 value.*



Rebuilding Afghanistan's energy sector

Afghanistan is starting to rebuild its energy sector and basic utility services after years of neglect and war damage as the troubled country tries to get back on its feet with help from the international community. While most of the Afghan population continues to eke out a subsistence level existence, work has recently started to restore mains electricity and piped gas supplies, while plans are under preparation to establish a new, deregulated energy sector and develop the land-locked nation's important indigenous energy resources. *David Hayes* reports.

Afghanistan capital, Kabul

Initial plans prepared by the Islamic transitional government of Afghanistan under President Hamid Karzai call for natural gas, coal and hydroelectric power resources to be rehabilitated and developed in order to reduce dependency on imported petroleum products. At the same time proposals are under study to build a gas transmission pipeline from Turkmenistan across Afghanistan to Pakistan and, possibly India, opening a long-planned southern gas export route from gas-rich Central Asia.

Building a modern energy sector poses a huge challenge for Afghanistan. After two decades of war and no investment in energy infrastructure, most equipment still in service is old, outdated and in poor working order. Human resources have also been neglected. Many public utility and energy sector engineers and technicians are approaching retirement and are unfamiliar with modern equipment and technology such as computers and automated controls.

Banks take leading role

The World Bank and Manila-based Asian Development Bank (ADB) are providing an international lead in helping rebuild Afghanistan's battered energy sector. The two development banks are coordinating their reconstruction efforts in energy, basic infrastructure construction and other areas where Afghanistan requires international assistance, such as developing health care services and rebuilding the education system.

Emergency work to restore electricity supplies to major cities involves rehabilitating hydroelectric and diesel-fired power plants as well as rebuilding electricity transmission and distribution systems. At the same time, the Afghan government has arranged to import electricity through cross-border grid interconnections with neighbouring Turkmenistan, Iran and Uzbekistan.

The emergency rehabilitation programme also covers the natural gas industry. Work is underway to repair and extend the existing natural gas transmission and distribution system, while technical assistance is being provided to develop gas production and repair gas pipeline leakages.

In 2003, Afghanistan launched a basic infrastructure rehabilitation programme backed by a $150mn ADB loan to rehabilitate its war damaged and poorly maintained natural gas, electricity and highway networks. Since then the World Bank and ADB have agreed to fund a series of technical assistance studies to review the Afghan energy sector, draw up a gas development master plan, advise on the creation of a regulatory framework for the gas industry, and to plan a national electricity grid development project for multilateral funding.

In addition, the Afghan government is involved in the ADB's technical and economic feasibility study programme on proposals to build the long-mooted Turkmenistan-Afghanistan-Pakistan gas transmission pipeline to transmit natural gas from Turkmenistan across Afghanistan to Pakistan and, possibly, on to India.

Energy plight and potential

In spite of its indigenous energy resources, Afghanistan has one of the lowest per capita energy consumption figures in the world, estimated at about 2,000 kW hours of electricity a year by the United Nations Development Programme prior to the Taliban regime taking control. Traditional fuels such as firewood, animal dung and agricultural waste account for about 85% of present energy supplies, while oil, gas, coal and hydropower provide the remaining 15% commercial energy share, half of which is petroleum products.

Afghanistan's energy plight is illustrated by the fact that fuel wood accounts for an estimated 75% of total energy supplies and is the basic energy source for cooking and heating in rural areas where most of the population live. Disruptions to urban energy supplies caused by war damage and infrastructure neglect have meant that a commercial market for firewood has also developed in urban areas, leading to uncontrolled cutting of forests for fuel and causing serious environmental damage.

However, in fact, Afghanistan is well endowed with natural gas, coal and hydropower potential. Known gas reserves are estimated at about 120bn cm, with additional reserves of 1,000bn cm thought likely at deeper drilling depths. Coal reserves are estimated at about 125mn tonnes, while Afghanistan's underdeveloped hydropower capacity already accounts for 68% of the nation's current power generation capacity. Domestic crude oil reserves are insignificant, however. Imports consequently account for most petroleum product requirements.

Government control

Government control of the energy sector is exercised through various ministries while operational functions are delegated to state-run enterprises. The oil, gas, coal and electricity industries are controlled by the government which acts as owner, regulator and policy maker. The Ministry of Water and Power (MOWP) is in charge of the electricity industry, while the Ministry of Mines and Industries (MMI) is in charge of oil exploration, gas, coal and mining. The Ministry of Commerce has responsibilities including oil product imports and distribution.

The experience of other developing countries in attracting long-term private investment to help finance energy sector development suggests that the government will need to establish a sound business environment supported by the rule of law, open entry and defined property rights.

While Afghanistan starts to rebuild its energy infrastructure, new data is being collected to begin replacing the large amount of information on Afghanistan's energy resources that has been lost during the past two decades. The offices of the Department of Geological Survey and Mineral Resources, for example, suffered a direct hit during fighting in Kabul. The only surviving information is contained in documents that Geological Survey staff had transferred to their own homes for safekeeping.

Importance of gas

Natural gas is Afghanistan's most important indigenous primary energy resource. While current gas production is confined to northern Afghanistan, the country's estimated, but currently unproven, 1,000bn cm of additional gas reserves lie in the western region near the city of Herat.

Afghanistan's gas industry dates back to the late 1950s when the government began extensive exploratory surveys for oil and gas with the help of the former Soviet Union. Eight gas fields were discovered near the city of Shebarghan in northern Afghanistan, of which three were developed. The remaining five gas fields remained untouched.

Gas production first began at Shebarghan in 1967 after completion of a pipeline to the northern border with Uzbekistan, where it connected to the main gas transmission line transiting Turkmenistan to European Russia. In the early days of gas development most of the gas produced was exported to the former Soviet Union under an 18-year government-to-government agreement. Gas exports terminated in 1987 with the ending of Soviet domination in Afghanistan. The gas export agreement was not subsequently renewed.

Since exports stopped most natural gas production has been used in Sheberghan and the nearby city of Mazar Sharif. Reserves in the three gas fields have depleted over the years. Currently the combined remaining reserves in the three fields is estimated at 15bn cm.

Afghanistan's domestic gas grid consists of transmission pipelines running 135 km from Sheberghan to Mazar Sharif. Pipeline distribution systems serve a population of about 300,000 people living in the two cities and a number of smaller towns and villages along the transmission route. Major customers include a fertiliser factory and its 48-MW captive gas-fired power plant along with textile and food processing plants, bakeries and other clients. Gas is also supplied to a number of households for cooking and heating. Residential gas use is unmetered and the tariff collection rate is understood to be very low.

Gas production at Sheberghan is about 600,000 cm/d at present, which is about 20% of its former peak production of more than 3.3mn cm/d in the early 1980s. Foreign gas engineers appointed to inspect the producing fields and pipeline grid estimate that about 250,000 cm/d, or almost half of the present gas production, leaks to the atmosphere, posing a major safety hazard and constituting a large waste of gas.

Gas and pipeline rehabilitation

Estimated to cost $24mn to implement, the natural gas production and pipeline rehabilitation section of the government's ADB-funded basic infrastructure rebuilding programme is designed to stem these large gas losses from the ageing and poorly maintained gas pipeline network, allowing piped gas supplies to be increased to new industrial and commercial customers.

Afghan Gas, under the Ministry of Mines and Industries, is the implementing agency for the project. The utility has appointed contractors for two turnkey projects to rehabilitate producing gas fields and upstream facilities, and to repair and rehabilitate gas transmission and distribution pipeline facilities. Afghan Gas also has appointed consultants to assist in the selection of a supplier of transmission and distribution line pipes. Other tasks assigned to the consultants include pipeline construction and rehabilitation supervision, ensuring quality control and supervising the commissioning of various facilities due for installation.

According to details earlier announced by the Manila-based ADB, contractors appointed for the project will rehabilitate 12 producing wells near Shebarghan to enhance gas production and prolong the gas field life. Some non-producing wells will be worked over and uncompleted wells will be re-evaluated. A cathodic protection system will also be installed to safeguard buried pipelines against corrosion. In addition, pigging facilities need to be installed to clean the pipelines internally as the pipeline's transmission capacity has been reduced due to a lot of condensate accumulating owing to a lack of dew point depressants. The project also includes the repair and reconstruction of corroded gas distribution lines, including the installation of city gate stations.

Master plan

With the emergency gas grid rehabilitation programme underway, the government has started preparing for the long-term development of the gas industry. The ADB is funding consultancy costs for several technical assistance projects intended to draw up a master plan for gas sector development, strengthen Afghan Gas' institutional capability and to plan a gas industry regulatory framework to support the future development of a modern, efficient gas industry supplying reasonably priced gas.

While the gas master plan has yet to be completed and approved, the government is keen to see the gas transmission and distribution system extended to Kabul and other major cities and towns where industrial, commercial and residential consumers can be served. The bitterly cold Afghan winters will create peak demand for gas supplies that will replace the current reliance on fuel wood. Gas could also be developed to fuel power generation should sufficient supplies become available.

The proposed TAP (Turkmenistan-Afghanistan-Pakistan) gas transmission pipeline could provide an additional source of gas supplies should indigenous reserves prove insufficient in Afghanistan. At present the ADB is due to appoint a new team of consultants to carry out a new technical and economic feasibility study on the proposed TAP pipeline. The decision to appoint a new team of consultants follows rejection by the tri-nation TAP gas pipeline project ministerial steering committee of the original, recently completed pipeline route and feasibility study prepared by Penspen of Britain.

Meanwhile, most recently, in July 2004, the ADB approved a technical assistance grant for consultants to design an effective and independent regulatory system for the Afghan piped gas industry. Plans will be drawn up to establish an independent regulator, based on international best practices, including a set of rules, laws and a framework for the regulatory authority most suited to Afghanistan.

'The government needs an independent gas regulatory authority in order to move ahead quickly with developing the sector, ensure more efficient use of resources and attract private capital,' commented ADB Senior Energy Specialist, Najeeb Jung. 'This will give confidence to private investors and ensure equal opportunities for the public and private sectors... A gas regulatory framework tailor-made to the country will protect the interests of consumers, ensure competition, minimise the negative environmental and social impacts of gas sector development, and ensure sustainability.'

Kabul street scene

Coal developments

Coal is another indigenous resource the government would like to develop. Coal production currently is estimated at about 180,000 t/y combined at about five coal mines that lie in areas controlled by local war-lords. Current coal production is less than one-third of output in the 1980s. Most mining equipment has been looted and mining structures have been destroyed. Mining licences have not been issued to the mine operators who do not pay taxes or fees to the government.

Coal is used for a variety of small industrial and commercial uses such as food preparation and baking; also as fuel in the home. According to World Bank estimates, Afghanistan's coal mining industry could increase its production to about 800,000 tonnes annually in five years once the necessary regulations and controls are put in place. Longer term opportunities include mining coal for power generation.

The development of coal mining will form part of a wider programme to encourage the exploitation of Afghanistan's hydrocarbon, mineral and quarry resources that will require private sector finance and foreign technology to replace current primitive mining methods.

Expanding power access

Meanwhile, both the World Bank and ADB are helping Afghanistan prepare projects for multilateral soft loan finance to rebuild and expand the nation's electric power industry. Access to electricity is one of the lowest in the world, with only 6% of the Afghan population connected to a public grid system. Currently, just 234,000 households are connected to a public power system, of which 70,000 are in Kabul. Access to electricity is less in other provinces, while rural areas are largely unserved. Even for those fortunate enough to be connected to a grid, power is available for only a few hours every day.

Afghanistan's installed electricity generating capacity is just 450 MW, of which only about 270 MW is available. Most power plant units either require overhauling or replacement.

There is no national power grid. All electricity networks are located around major cities and industrial areas. Electricity distribution systems are in a dilapidated condition due to war damage, lack of maintenance and theft of parts for the past 25 years. Power losses are estimated at about 45%, partly due to technical losses in transmission and to theft or non-payment of electricity bills.

Big changes are in the offing, however, as Afghanistan joins the 21st century. Staff training will be important for the electricity industry and energy sector as a whole as new equipment begins to be installed.

The ADB is providing Da Afghanistan Breshna Moassesa (DABM), the Afghanistan Electricity Authority, under the Ministry of Water and Power, with project preparation technical assistance to plan reconstruction of three regional electricity transmission grids. The eventual project is due to receive ADB loan finance support.

As part of efforts to promote economic growth, the government wants to rebuild and interconnect the northern, northwestern and central power grids. DABM's project also will involve constructing power lines to supply the Badghis, Faryab and Jawzjan provinces that are not connected to any grid at present.

Other facilities to be built include an 800-km, double-circuit 220-kV transmission line from Mazar Sharif to Heart and new 220/20-kV substations. DABM will build a new load dispatching centre in Kabul to control the dispatch of electricity from its own power plants and electricity imports from neighbouring Uzbekistan, Turkmenistan and Iran.

The World Bank is due to provide DABM with project preparation technical support to prepare a load application for a $260mn scheme to rehabilitate and develop electricity distribution in Kabul and other cities. The eventual project will include rehabilitating Afghanistan's existing hydroelectric power stations, including the 100-MW Naghlu dam. In addition, the loan application is intended to secure finance to build a 220-km long, 220kV transmission line from Pulikhumro to Kabul to improve electricity supplies to the capital.

Reliance launches petrol station network

Main picture: First prototype site in New Bombay with the base transducer station in the background. Below left: Computer visual of night-time image. Below middle: Close-up of dispenser. Below right: Computer visual of the truck driver amenity centre (Dhaba).

To coincide with deregulation of the Indian state-run petroleum retailing sector, design company Minale Tattersfield was commissioned by Reliance Petroleum, in 2001, to design and brand a new network of petrol stations. *Petroleum Review* reports.

The commission comprised full-blown truckstops at highway sites, regular fuel sites on trunk roads and city sites, together with outlets aimed at the rural farming community who traditionally arrive on-site with tractors and trailers carrying vessels to be filled.

Reliance Industries is one of India's largest privately owned companies. It has recently completed a 27mn t/y grassroot refinery at Jamnagar in the Indian state of Gujarat, with the refined product to be sold through the retail outlets. In parallel to this project, the company also embarked upon construction of a new telecommunications infrastructure which included covering India with a network of fibre-optic cabling and transducer towers. Part of the remit for Minale Tattersfield was to design the architectural elements and create the branding components for the new Reliance Infocomm company as well as design the 1,000-strong network of Webworld-branded phone shops.

Significantly, all fuel retail outlets will be included within the telecommunications network – which gives Reliance a competitive advantage in terms of wet-stock management and offering the all-important trucking community a tailor-made banking, communication and load-matching service.

Phase 1 of the implementation programme is currently in the region of 100 sites strong. The prototype site at the company headquarters complex in New Bombay (Navi Mumbai) was opened in 2004 and is currently turning over three times the expected sales volumes. Initial studies indicate that consumers are aware that Reliance has taken extra care to maintain quality and quantity of the fuel product. The existing state-run companies have previously had a bad reputation in this regard and therefore a key consideration in the design process was to differentiate the Reliance brand as far as possible from its contemporaries. To this end a modern design was created using curves together with colour-branding of blue, green and silver.

Currently under construction on the Baroda-Ahmadabad expressway is a retail outlet with a multi-food brand rest facility aimed at car/coach passengers. The corresponding service for truck drivers is far larger and includes sleeping, washing, entertainment and food facilities. The architecture was deliberately more rustic in order to appeal to the average truck driver. The first 'Dhabas' as they are called locally have been open for a year now and are again performing above expectation. In order to provide the full range of offerings to the motoring public, vehicle service centres are also available.

Creating an effective gas supply network to Europe

In the first of a two-part article, *David Wood and *Bill Pyke*** argue that the creation of an effective gas supply network to Europe requires the integrated development of both pipeline and LNG markets.**

Gas demand growth and concern over security and diversity of supply in Europe is driving the need to build new LNG import terminals and gas storage facilities in addition to inter-continental pipelines and interconnections (cross-border) between national gas transportation grids. It is an integrated approach involving both LNG and pipeline supplies that is likely to provide Europe with the most efficient and reliable gas supply web[1] in the long term.

Most European countries, excluding Norway, are becoming increasingly dependent on natural gas imports in their energy supply mix, with growing inter-dependence between their gas and electric power markets. If good systems of governance are in place the experiences of deregulated gas and electricity markets in the US and UK suggest that opening up of these markets can substantially improve security and reliability of supply, promote private investment in appropriate infrastructure and link consumer prices to market forces.

However, it is also clear that governments have to play an ongoing role in stabilising and maintaining their open markets, and in long-term planning for favourable and integrated market development. Unbundling of businesses from monopolistic state-controlled utilities can leave a vacuum in the broader integrated planning roles. Government regulators should prevent monopolistic practises by monitoring the gas supply industry. This will ensure transparency. Perhaps equally important is the ability of regulators to provide governments with market insights that can help to evolve fiscal frameworks to stimulate investment in supply grids and improve flexibility.

Role of LNG

European and US gas consuming markets are currently dominated by pipeline supplies. However, they are increasingly relying on the LNG trade and above-ground and sub-surface gas storage to provide increased flexibility and diversity of supply. Security of supply becomes a more complex and higher-profile issue as indigenous supplies deplete and linear gas chains evolve into networks and webs. The issues do not stop at national borders and, as is the case in the global oil markets, they can be influenced by events many thousands of kilometres away. Government regulators and gas supply companies must therefore take interest in each component in the web that potentially can contribute to each nation's gas supply. LNG plays a key role in bringing gas to market when distance or political obstacles make gas transport via pipeline unattractive or too risky.

LNG could start to impact the dominance of pipelines in the EU gas market if the substantial investments planned by the majors and utilities along several LNG supply chains to Europe deliver according to expectations, bringing more flexibility, diversity and security to EU gas supplies. Over the past decade cost reductions in liquefaction, shipping and storage have made LNG more competitive in terms of delivered price when compared with gas transported long distances by pipeline.

Post-Enron and the failure of US merchant gas traders to penetrate the European gas market, major energy companies have also recognised that control of reserves, facilities and distribution assets must underpin physical and paper trading of gas supply to reliably extract value from regional gas markets over the long term. Consequently, gas exporters and importers have been scrambling in recent years to take equity positions along the full length of the LNG chain in an effort to extract maximum value from their LNG supply businesses and match specific gas supply with contracted demand.

However, for LNG supplies to be exploited consuming countries must invest in receiving terminals and storage facilities that link effectively into their domestic gas distribution networks. A point of much ongoing debate is third-party access (TPA) to the receiving terminals. On the one hand, TPA is required to avoid monopolistic or market manipulation practices by the utilities that wish to continue controlling the gas distribution network in their respective countries. On the other hand, in order to secure the investment from the utilities (and majors) to build new receiving terminals at strategic import locations, derogation of strict TPA rules are required (such as the Second Gas Directive (2003) – Article 22, Exemption Status) in certain cases to ensure that investors are able to achieve realistic returns. Throughout TPA arrangements for pipeline distribution systems also require simplification with entry-exit tariffs for transmission (eg UK) replacing complex distance related schemes (eg Germany).

It is at the receiving terminals, the point of import of LNG into Europe, that competition is at its fiercest between majors (with their dominance in upstream LNG supply combined with strategies to penetrate markets) and the national utilities (with their dominance of the distribution networks combined with strategies to protect their strangleholds over customers). Long-term buyers of LNG are now commonly offered equity participation in the upstream end of the LNG value chain, providing them with diversification opportunities in exchange for enabling suppliers to secure long-term market penetration. As the majors have learnt, just finding gas is not enough,

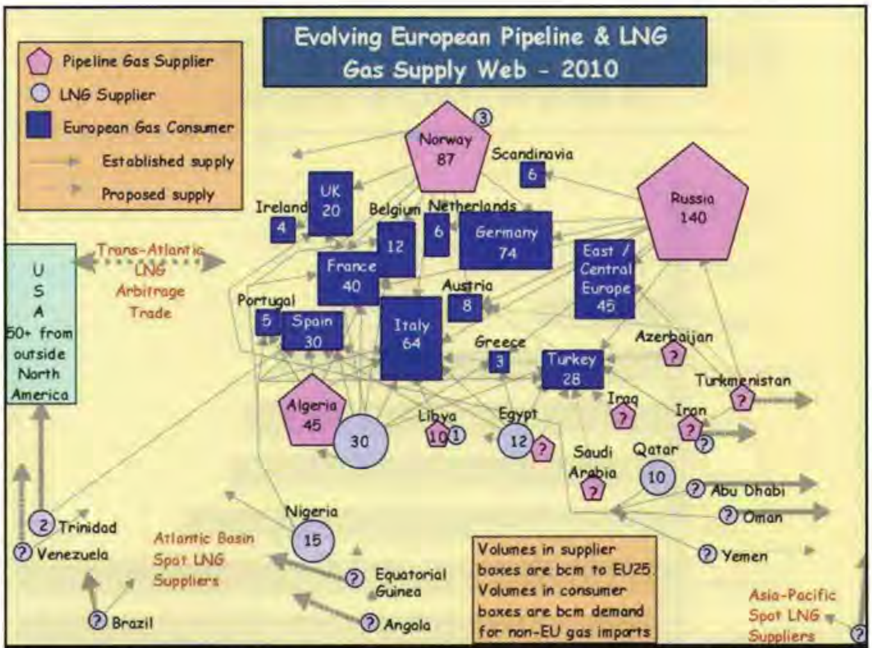


Figure 1: EU gas market as an evolving web of demand with pipeline and LNG imports increasingly replacing indigenous supply

an integrated strategy and control of market infrastructure is needed to monetise it.

The ability to physically re-direct LNG from time to time to the highest value market, combined with open third-party access to many receiving facilities, enhances LNG's flexibility and the role it can play in providing security of supply. The contractual flexibility to allow buyers of LNG to sell on to third parties is an essential part of the evolving European gas market that is increasingly looking to exploit arbitrage and short-term trading opportunities. Government planning and fiscal policy can help to ensure that the LNG trade develops without market barriers, by streamlining administrative procedures. This has to be done without losing sight of the need to maintain the highest realistic safety and environmental standards.

Key challenges for the European gas market are to reconcile competition in an evolving internal market with the need for strategic security and diversity of supply whilst promoting access to the larger, more distant external reserves of gas to secure long-term future supplies on competitive terms at appropriate times. Although an expanding role for short-term and spot contracts will help to improve internal competition and solve micro-supply issues, long-term supply contracts remain essential to secure investment in the infrastructure required to provide access to the more distant reserves.

Figure 1 illustrates the web of European gas demand and gas imports from non-EU pipeline and LNG suppliers that is likely to have evolved by 2010.

Liberalising European markets

A fundamental shift in the political and commercial culture during the 1980s led to a steady liberalisation of the market for natural gas, firstly in the US and then in Britain. The UK 1986 Gas Act paved the way for a pan-European break-up of state energy utilities. These companies had previously operated monopolistic control of the various supply, distribution and marketing networks. Importantly they controlled and regulated prices. From the late 1980s the unbundling of their distribution networks, access to markets, price and tariff transparency and third-party access to pipeline transmission ensued – albeit in some cases at a snail's pace.

The 1998 EU Gas Directive required member states to legislate for the opening of the first stage of their gas markets by 2000, moving towards total market liberalisation and harmonisation of the European gas market. These measures included unbundling of restricted distribution and market networks owned and operated by state-supported monopolies in energy supply, transparency in prices and tariffs, and third-party access/common carriage through pipeline networks. The milestone dates set by this directive were not met by most member states (see **Figure 2**).

European Union (EU) member states enacted national laws before July 2004 to comply with the second EU (acceleration) gas directive[2] aimed at rescheduling the deadlines for creating a liberalised internal gas market. However, this latest schedule means that it will probably not be before 2007 that it is possible for international gas suppliers to establish whether access to the markets of the major-state liberalisation laggards (such as France and Germany) is commercially viable on competitive terms with the incumbent state-controlled utilities.

To date, full market liberalisation has only been achieved in the UK and Germany, representing more than 50% of EU gas demand – however, in the case of Germany, this is on paper only. Germany has yet to put into effect practical measures that facilitate TPA to its pipeline network to enable foreign companies to compete effectively with Ruhrgas (E.On) or RWE.[3]

Meaningful and effective competition can only take place when the infrastructure-access regimes set out in the EU directives are fully adopted and functioning at the national and cross-border levels. Many of the 2004 accession states, plus Finland, Greece and Portugal, qualify as emergent markets and, as such, are entitled to derogation of many of the deadlines set by the directive. Short-term consequences of obfuscation, delay and inconsistent implementation or interpretation of the directive impede competition and maintain the artificially high consumer gas prices that exist in the closed sections of the market.

Impact on LNG and gas-to-power

One consequence of open market harmonisation and the vision to create a single gas market for Europe is to provide regasified LNG volumes third-party access to pipeline distribution networks. The real threat to LNG expanding its penetration into the liberalised market remains resistance encountered from national governments and major infrastructure controllers. If there are restrictions placed on access, tariff arrangements and price schedules it will act as a disincentive for investment in LNG expansion.

Another consequence of market liberalisation is concern of financiers about investing in LNG infrastructure projects in which owners cannot ensure maintaining high long-term shares in the markets to be supplied. This contrasts sharply with the immediate past where state monopolies could ensure their market dominance.

The evolution and development of combined cycle gas turbines (CCGT) heralded a cost-competitive and environ-

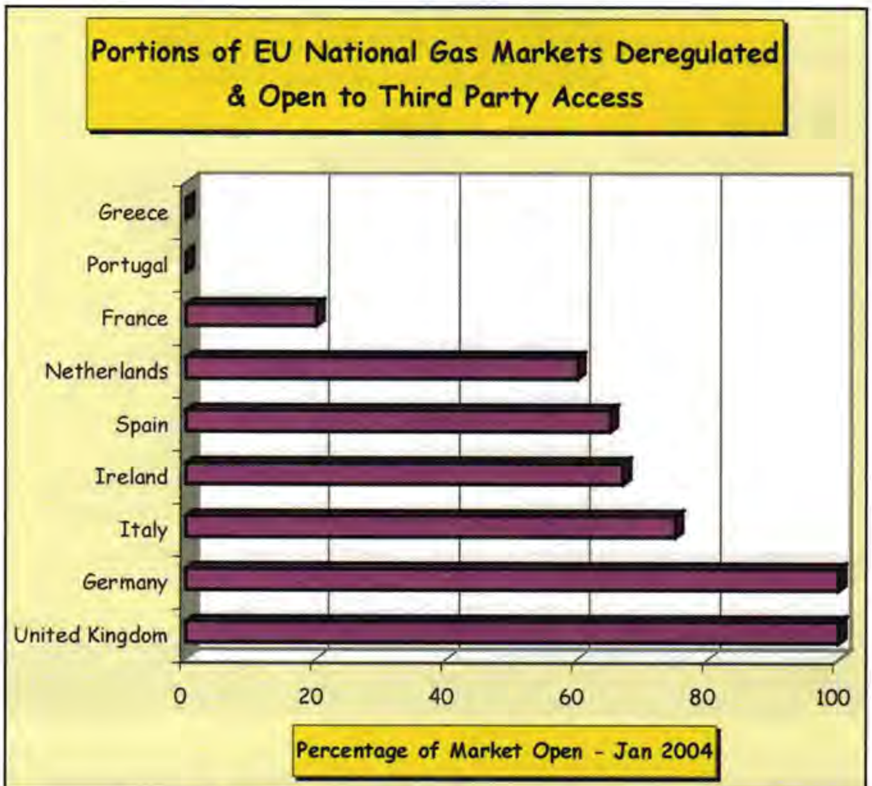


Figure 2: Official status of gas market liberalisation in EU countries (January 2004)
Source: Nathalie Vande Velde (2003), 'Completion of internal market for Energy: An update', DGTREN Electricity and Gas Unit European Commission, European Commission (2004) Pocket Book, Energy

mentally more acceptable alternative to coal and oil-fired power stations. Demand in the gas-to-power sector is anticipated to rise to 181bn cm by 2010.[4] Competition in gas supply should enhance investment in building more CCGT plants across the EU. Gas is now the default fuel for companies wishing to expand their position in the power sector. As delivered prices for LNG and pipeline gas continue to converge more CCGT facilities will be built adjacent to LNG receiving terminals to exploit LNG's supply flexibilities.

The first three-year phase of the emission trading scheme (ETS) starts in January 2005 (see *Petroleum Review*, July 2004). Designed to reduce greenhouse gas emissions, it covers some 12,000 EU installations, of which power generation accounts for 55% of the emissions. Installations failing to comply will face financial penalties and risk having their credit-ratings downgraded. ETS will provide a further boost to efficient CCGT developments to replace high-polluting coal-fired and oil-fired plants. How effectively the EU's long-term strategy for the power sector is implemented could determine, along with deregulation and investments in renewable energy projects, how successful LNG is in competing for a much larger share of the EU gas market.

The speed and extent to which nuclear and coal-fired generation plants are decommissioned and replaced by CCGT will determine whether LNG is contracted to supply base-load gas to north-west Europe in the long-term. Use of nuclear and coal as energy is a high profile issue in France, Germany and the UK, with each country holding different views and aspirations for those sectors. Cost-effective new technologies that reduce emissions from gas-fired plant, if developed, could yet undermine the ability for gas to replace coal to the extent forecast by most analysts. The accession of eastern European countries to the EU will now add to the voices of France, Finland, Sweden and Switzerland in promoting an expanded role for nuclear power to meet long-term EU energy needs.

Gas pipeline supply

By the close of 2004 some 40% of Europe's gas will have been supplied by Russia, Norway and Algeria, mainly by pipeline. All three of these sources are likely to grow in importance, perhaps rising to as high as 70% of supply by 2025. Russia dominates the market, particularly in eastern and central EU states. It is trying to extend its customer base (eg UK) but will have to share that market growth with other sources, notably Norway and the Netherlands, and LNG. Diversity and security of supply place ceilings on the EU's appetite for Russian gas and, as a result, Russia is also looking east to monetise additional volumes of gas through pipeline projects to China and Japan (see *Petroleum Review*, November 2004). However, long-term contracts purchasing Russian gas will be the price makers for EU gas supply for the foreseeable future.

Russia is keen to extend its pipeline infrastructure into the EU market, although it is at present not clear how Gazprom will find sufficient capital for all the projects planned. The Northern Trans-Europe (NTE) 20-plus bn cm/y pipeline, incorporating a 1,300-km route beneath the Baltic Sea from Finland to Germany, has the most appeal as it bypasses potentially problematic eastern European countries and avoids cross-border transit tariffs. It would, however, cost some $6bn. Twinning the Yamal-Europe pipeline and expanding pipeline capacity through Ukraine is another option being considered. Centrica announced in August 2004 its intention to take a 10% stake in the £3bn RUE gas pipeline project to ship gas from Turkmenistan through Ukraine (and Austria).[5]

The UK is the focus of significant expansion in pipeline connections, with the 1,200-km Langeled pipeline linking Norway's giant Ormen Lange gas field to Easington, on England's east coast, importing some 15-plus bn cm/y by 2007. The UK-Belgium Interconnector is having capacity raised from 8bn cm/y to 16.5bn cm/y by 2005, while the Bacton-Balgzand (BBL) pipeline interconnector (UK to the Netherlands) could import up to 16bn cm/y of gas by 2007, perhaps from Russia, but with the flexibility to include gas from other sources. This 235-km pipeline requires the EU to approve TPA restrictions to enable Gasunie, Ruhrgas and Fluxys to justify some $500mn investment. The BBL interconnector will initially supply Centrica in the UK with gas from the Dutch North Sea, but widen supply to other gas passing through continental Europe in the longer term.

Meanwhile, North Africa remains the most competitive gas supplier to the Mediterranean EU states. Although Algeria dominates supply to Spain and Italy, it will face increased competition from Egypt and Libya from both piped gas and LNG. The two existing deepwater subsea lines from Algeria to Europe are the 9bn cm/y Pedro Duran Farell pipeline to Spain through Morocco and the 24bn cm/y Enrico Mattei pipeline to Italy through Sicily.

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Developing a strong position in the Asia-Pacific

Continuing with our series of articles analysing some of the smaller and intermediate oil and gas companies from around the world – based on information supplied by *Oilvoice.com– we take a closer look at the activities of *Amerada Hess.***

Amerada Hess is a leading global independent energy company, engaged in the exploration and production of crude oil and natural gas, as well as in refining and in marketing refined petroleum products, natural gas and electricity.

Global exploration

Amerada Hess directs over 95% of its total capital expenditures to E&P exploration, development and production activities in the US, UK, Norway, Denmark, Equatorial Guinea, Gabon, Azerbaijan, Thailand and Indonesia. The company's exploration programme focuses on high impact prospects in core growth areas, also participating in lease sales and farm-in opportunities to develop acreage holdings and potential exploration areas. Between 15 and 20 wildcat, appraisal and exploration wells are drilled each year in order to ensure an annual reserve replacement in excess of 100%.

Over the last few years, the majority of spending has shifted from producing fields to development projects as the company builds a platform for 'long-term profitable growth'. Amerada Hess is currently funding a dozen key development projects that will add more than 100,000 b/d of new production by 2006 and contribute to lower unit costs and a longer reserve life. These new projects, as well as positive results from the company's exploration programme, are expected to add significant resources to the existing proven reserve base of over 1 bn barrels.

Strong Asia-Pacific position

In recent years, Amerada Hess has built a portfolio of producing and development assets that provide a significant position in the Asia-Pacific's growing gas supply market. The company also has interests in a number of prospective exploration blocks offshore Malaysia, Indonesia and Brunei, where an active programme of seismic acquisition and drilling is planned over the next few years.

A regional centre has also been established in Kuala Lumpur, Singapore, to provide a hub for technical and business services to support the growing business in the Asia-Pacific region. Country offices have also been established in Jakarta and Bangkok.

Asia-Pacific assets include Amerada Hess' 25% working interest in block A-18 in the Gulf of Thailand following its acquisition of Triton Energy in 2001. A further 25% interest was acquired from BP in an exchange for interests in Colombia in 1Q2003. The block is operated by Carigali-Triton Operating Company, a 50:50 joint venture with Petronas Carigali. It contains the Cakerawala field and production facilities, together with an additional seven discoveries. A Phase 1 gas sales agreement has been put in place with Petronas (Malaysia) and PTT (Thailand), involving reserves of 2.85tn cf of gas and production of 390mn cf/d. Production facilities are completed and awaiting hook-up. A pipeline is currently being installed and a gas plant under construction. First production is expected during 1H2005.

In the meantime, the Pailin field

Figure 1: Amerada Hess' core E&P activity and average production in 2003 (in boe/d)

(Amerada Hess 15%) offshore Indonesia has been in production since August 1999. Gas is exported via an existing pipeline to the mainland, with liquids evacuated to a floating storage unit. Phase 2 production started in July 2002, with contracted volumes doubling to 300mn cf/d.

Amerada Hess restructured its portfolio in Indonesia with the sale of its interest in Jabung in April 2003. Natuna block A was also acquired in 2003 from Premier Oil. Production is onstream and, under the existing gas sales agreement, is delivered to Singapore through the 403-mile West Natuna pipeline system. Amerada Hess is also currently in the process of securing a gas sales agreement for the Pangkah PSC (66% stake), while development options for the Jambi Merang PSC (25%) are under evaluation.

Meanwhile, in the onshore Esarn region of north-east Thailand, Amerada Hess is currently conducting final appraisal of its Phu Horm gas discovery (35% interest). In advance of project sanction, the company has also commenced an environmental impact assessment (EIA). Consultation on this document is currently underway with local communities and other interested parties.

Other operations

In the Gulf of Mexico, additional appraisal drilling is ongoing on the Shenzi prospect (Amerada Hess 28%). Following the initial discovery in 2002, the Shenzi-2 appraisal well encountered about 500 ft of net oil pay (compared to Shenzi-1 at 140 ft of net oil pay) in 2003. Further appraisal drilling is also planned in 2005 to determine the extent of the Tubular Bells discovery located in approximately 4,300 ft of water. Additional appraisal drilling is planned on the Chinook discovery (Amerada Hess 15%), drilled in water depths of approximately 8,830 ft.

More recently, in September 2004 Dana Petroleum reached agreement with Amerada Hess to acquire an additional 28% interest in the UK North Sea Hudson oil field, thus increasing Dana's total stake to 47.5%. In exchange, Dana will transfer its wholly-owned Indonesian subsidiary to Amerada Hess, along with a balancing cash consideration payable at completion.

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There is potential to substantially expand the capacity of these existing lines, but a direct 8bn cm pipeline to Spain (Medagaz) that avoids Moroccan transit tariffs is planned for 2007, while a second 10bn cm pipeline (Galsi) to Italy is also under consideration.

The 10bn cm/y Green Stream pipeline from Libya to Italy is nearly completed and is due onstream by 2005.

Turkish role

Geopolitics and large capital investments in projects crossing risky terrain are the main obstacles to pipeline links from western Europe to the Caspian gas suppliers (Turkmenistan, Uzbekistan and Kazakhstan) and to the major Middle Eastern gas reserves holders such as Iran, Saudi Arabia, Iraq and Egypt (already linked to Jordan by pipeline).

The most commercially attractive routes are through Turkey. Russia believes otherwise in the case of Central Asian Republics, but then it wishes to continue to control supply from those potential competitors. Gas from these Central Asian Republics is strategically important to Russia (especially Gazprom) – as it can supply a cheaper, more immediate source of gas than from remote undeveloped fields in North Russia (offshore or Artic Siberia).

Gazprom is investing heavily in these countries in order to maintain development control over their internal pipeline networks and potential export routes. Russia may even foster aspirations to lead a cartel of gas producing countries akin to Opec, possibly involving Russia, Central Asia and Iran. Iran is already connected to deliver gas into Turkey through the modern Eastern Anatolia pipeline. This currently operates at less than capacity due to Turkey's current glut in gas supply. This situation is also likely to delay a number of gas pipeline projects bringing gas into Turkey (including the Trans-Caspian Pipeline from Turkmenistan and South Caucasus Pipeline from the Shakh Deniz field offshore Azerbaijan through Georgia), which may not be in Europe's best strategic interests.

Potential pipeline routes through Turkey have been planned for many years. The most popular routes, each importing up to 20bn cm/y, are:

- The 4,500-km Nabucco pipeline route from Turkey through Bulgaria, Romania and Hungary, terminating at Baumgarten, Austria. (Baumgarten handled around a third of Russian gas exports to western Europe in 2003.)
- Turkey-Greece-Italy (Brindisi) route. The latter avoids non-EU eastern Europe transit tariffs and risks, and thereby may find it easier to secure EU financing and could subsequently be branched to also deliver gas into Bulgaria and the Balkans. However, as well as geopolitical problems east of Turkey, strained relationships with neighbour Greece also add risk to pipeline infrastructure projects crossing this region.

When either of these pipelines is built Turkey will become a key strategic gas transit country into Europe. However, Austria's involvement with Gazprom and Naftagas in the planned RUE pipeline route from Turkmenistan through Russia and Ukraine, indicate that Turkey is facing strong competition from traditional alternative routes.

Footnotes

1. The term 'gas web' is used here to refer to an integrated system that inter-connects a series of national gas transmission/distribution networks and gas supply chains.
2. Directive 2003/55/EC of 26 June 2003 required the opening of the gas market to all non-household customers by July 2004 and to all customers by July 2007.
3. *Petroleum Economist*, July 2004.
4. Cedigaz, 2003.
5. Partners in the RUE venture are Gazprom, Naftogas (Ukraine's state gas company) and Austria's Raiffeisenbank – the latter selling part of its 50% stake to Centrica.

Part 2 of this feature will appear in the January issue. It will look at the key LNG buyers in Europe and address potential gaps in future gas supplies.

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Decentralisation – has the pendulum swung too far?

***Mark Turek*, Senior Operations Manager at Celerant Consulting,* looks at how many companies in the oil and gas industry are turning full circle, moving away from decentralisation and back towards central control of their operations. However, while centralisation may well achieve a level of consistency across an organisation's activities, Turek asks: 'How then does it manage not to stifle continuous improvement?'**

Some might say that the recent events at Shell have brought into sharp focus the need for a strong, robust corporate centre – an entity that takes responsibility for controlling an increasingly widespread portfolio of global business units. However, as we know, in today's marketplace growth from the industry's major players is achieved more and more through partnering and joint ventures.

The centre will, of course, always assume some obvious roles, namely, protecting and managing the interests of shareholders – issues of governance, reputation, corporate finance and strategy to name a few. But many companies have found that operating globally has meant having to loosen their grip on business units in order to accommodate local needs and cultures. And this means organisations need to demonstrate more collaborative and flexible approaches, to allow greater autonomy and make manifest their willingness to adapt to other ways of working.

Clearly, there is a fine line to be navigated between controlling from the centre and working in more dynamic and entrepreneurial ways. It is a balancing act that global organisations face every day.

Until the early 1980s, oil and gas companies were heavily centralised. This was very much a function of close interrelationships – vertically between exploration, production, refining and marketing, and horizontally between the final products. This arrangement worked well during a period marked by a stable and relatively predictable environment. However, with the turbulence that followed the oil crises of 1973–1974 and 1979–1980, the principles that governed operation in a stable environment were no longer applicable.

Oil and gas companies needed to adapt to a rapidly changing environment. The old bureaucratic structures needed to be replaced by new models that provided operating units with the flexibility and freedom to respond quickly to the changes taking place around them.

This was later compounded by years of merger and acquisition when operator acquired operator and, in doing so, inherited the complexity of existing practices and ways of working. One could argue that integration needed to be accomplished quickly, meaning that operating units needed the flexibility and autonomy to achieve this, without reverting to or being constrained by the centre.

Likewise, in new or emerging environments, autonomy and decentralisation provide the flexibility to adapt.

But has the pendulum swung too far? Had common processes and procedures already existed during the period of mergers and acquisitions it may have created a different and possibly more effective platform from which to achieve more rapid and consistent integration.

Centralisation versus decentralisation

In opening up the debate, talking about centralisation versus decentralisation isn't necessarily helpful. It isn't always a case of 'either, or'. In practice, organisations are never completely decentralised or centralised. The issue is more one of degree. This has less to do with the 'formal' design and intent of the centre – and everything to do with relationships. How does the centre see its role and, consequently, how does it behave towards its operating units?

There are, of course, many reasons that typically guide the thinking and behaviour of the centre. There is the established culture of the organisation itself, often developed and nurtured over many years, in which the role of the centre was fully accepted by the organisation – in fact, it would be difficult for the business as a whole to imagine working any other way.

ExxonMobil, perhaps, is one good example of a company that has built a reputation on this basis. It is recognised for maintaining a strong centre from which policies and procedures are created, disseminated and delivered worldwide. What ExxonMobil has managed to create is a strong culture of conformance. Whether this represents the key to success is unclear, but its performance at least doesn't suggest centralisation has in any way created an environment that smothers business unit ingenuity or individual creativity.

This, of course, only works when the organisation has direct control over its entire operations. With partnerships and joint ventures, a very different mind-set is called for – this is particularly true where diverse cultural differences add to the complexity of the situation. In these cases, the centre must give autonomy and support to the local business unit's view on the ground. This is what the US army calls the 'ground reality' – the difference between what the command centre *believes* is happening and what is *actually* happening. In actuality, it is local knowledge, experience and, ultimately, intuition that are likely to inform and deal with the situation most appropriately.

That said, there is a renewed trend among the majors that is moving back towards centralisation and there are many good reasons why this should be the case. Firstly, oil and gas is a global business, with a mobile workforce constantly on the move. With this degree of movement comes the inevitable challenge of having to absorb new practices, processes and procedures with each move. In a performance-driven environment, pausing to acclimatise is a luxury and rarely a possibility. The industry needs to create conditions where individuals are protected, as far as possible, from unfamiliar environments and where they can focus instead on delivering what they are there to do – safely and efficiently.

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The Quito Virgin overlooking Ecuador's capital city stands at an altitude of 3,016 metres

Turning sustainable development into a strategic advantage

Sustainable development is considered a dirty phrase in many oil and gas company boardrooms. However, two academics now argue that it can give practitioners a valuable step-up over their competitors. *Gordon Cope* reports.

Pacalta Resources first began to look at Ecuador as an exploration target in the mid-1990s. Production from oil fields in the Amazonian rainforest east of the Andes stood in excess of 400,000 b/d, and geologists and geophysicists predicted a vast, untapped potential. Unfortunately, the Latin American country's woes were equally vast – outstanding disputes between the government and industry regarding taxation, investigations into pollution of the rainforest and disputes with indigenous groups over encroachment into ancestral lands.

Still, the Canadian junior oil company was optimistic about its chances for growth and, in 1996, purchased a field producing 4,500 b/d. When Pacalta President John Wright arrived in Ecuador, however, he discovered that the region was bedeviled by a problem that had the potential to derail oil production. As part of its land allocation policy, the government of Ecuador encourages *colonals* – landless peasants from the highlands – to migrate to the interior by formally transferring land adjacent to oil company roads. 'They get off a bus with a machete and a deed, and trudge into the forest to their plot of land,' says Wright. 'The first thing they do is cut down the trees, then plant some coffee, then bring in some cattle. The forest root system is destroyed and the land just washes away under 400 inches of rain a year.'

While the *colonals* were not innately aggressive, there was resentment that foreigners were getting rich while they lived in poverty. Road blockages and acts of sabotage to their predecessor's installations were common. This gave Wright cause for concern. 'The *colonals* were not a risk, they were a reality. But we wanted to start massive investments. We needed to get local people onside.' In the past oil companies had simply tried to buy off local officials, but the hard-nosed oilman intuitively knew that the situation required something more comprehensive. The trouble was, he didn't know *what*.

Dish up the stakeholders

According to academics Harrie Vredenburg and Jeremy Hall, Pacalta had entered into a classic 'stakeholder ambiguity' zone. 'Stakeholder ambiguity is a situation where it is difficult to recognise key stakeholders or reconcile their concerns,' explains Vredenburg. 'Such challenges are becoming increasingly important for firms competing in the global economy.'

Vredenburg and Hall are management scholars at the University of Calgary's Haskayne School of Business. Among their credentials, Vredenburg is Suncor

Energy Chair in Competitive Strategy & Sustainable Development. Hall is a Fellow of the TransCanada International Institute for Resource Industries & Sustainability Studies. Their research focuses on managing stakeholder relations in the area of sustainable development. Over the last 10 years they have conducted studies in over 50 companies in South America, Asia, Europe and North America, interviewing senior executives and managers from a wide range of industries, from retailing and aerospace to agriculture and energy. They have come up with the startling conclusion that, rather than being a burden to doing business, savvy companies can turn sustainable development into a strategic advantage against their competitors.

The concept of sustainable development arose several decades ago, when concerns over pollution motivated international organisations such as the UN to seek action. 'The classic definition of sustainable development is meeting the needs of the present without jeopardising the needs of the future,' says Hall. Originally, sustainable development focused primarily on environmental issues. 'The oil and gas sector has a number of issues when facing sustainable development – petroleum is not renewable, and there are the environmental worries of global warming.'

When NGOs (non-governmental organisations) focused media attention on oil spills, flaring of natural gas and decommissioning of ageing facilities, companies responded with what is now referred to as 'stakeholder management'. The process identifies various groups and causes that can either promote or threaten a proposed project, then assigns a value to them so that various means of dealing with issues can be addressed. One of the key factors to stakeholder management is identifying risk. 'Risk can be divided into hazard risk, such as the possibility of being hit by a hurricane, which is insurable, and investment risk, which is the variability of returns from an investment,' comments Hall. 'In either case, standard management practice considers both the probability of something happening as well as the magnitude.' Based on stakeholder management analysis, tanker hulls were doubled up, natural gas re-injected and offshore platforms recycled. Companies that nurtured sophisticated stakeholder management techniques learned to address these issues in an efficient and economical manner, leading in some cases to exponential growth for their firms.

Over the last decade, however, the concept of sustainable development has evolved to include social and cultural considerations. For instance, Monsanto – the designer of herbicide resistant GM (genetically modified) crops – suffered blows to its reputation and stock price when it failed to assure a wary public that its technical innovation was not only safe for people and the environment, but also would not enslave Third World farmers to their proprietary seed products.

These additional constraints not only add complexity, they also create a 'stakeholder ambiguity' situation. 'A definition of ambiguity is when you have two people with the same information, but they come to opposing conclusions,' says Hall. Under such circumstances, in which opposing factions have seemingly contradictory purposes, standard risk management practice is no longer applicable. 'How can you predict what Greenpeace will do, or its effect?'

Finding the pony

As dire as the situation sounds, Vredenburg and Hall have postulated an intriguing solution. In a recent paper entitled 'Stakeholder ambiguity and corporate risk strategies' (submitted to *California Management Review*, April 2004), the two academics argue that stakeholder ambiguity can create a strategic advantage for small, nimble firms over the supermajors. 'Look at large American oil and gas companies,' says Hall. 'They have economies of scale to give them an advantage below-ground. Small companies can't compete head on.' Above-ground, however, the risks change from technical to social and cultural, which significantly tilts the playing field against the heavyweights. 'A big company has everything to lose and little to gain. Look at Shell in Nigeria. For 20 or 30 years it took the policy of not interfering in internal politics – no corporate imperialism. But then Ken Saro-Wiwa was executed and people said: "Why didn't you stop it?" Big companies also see sustainable development as a hazard, a risk that can lead to danger and loss – you're damned if you do and damned if you don't.'

In a great many cases, say Hall and Vredenburg, the largest oil and gas firms avoid above-ground risks and the hassles of stakeholder ambiguity. Indeed, their risk assessment techniques often reject projects based on above-ground risks. Under these circumstances smaller rivals can actually use that ambiguity and uncertainty to their own gain. 'If sustainable development is embedded in a small company's business environment, it can be a competitive advantage,' explains Hall. 'They can see above-ground as an investment risk (as opposed to a hazard risk for the larger firms) because they can be competitive.'

Quito the solution

John Wright is first to admit that, faced with the situation in Ecuador, finding a strategic advantage through sustainable development was the last thing on his mind. 'We had seen problems with the local people. We were concerned that there might be trouble getting the job done. At the same time, we didn't want to cause human suffering. The bottom line is, we're good guys, parents, environmentally conscious.'

By chance, Wright met Jim Geenen, a social worker stationed in Quito. 'Geenen and I started to talk,' says Wright. 'He was working for Plan International; they give stuff away, it was very paternalistic, he was disappointed with the results.'

Wright and Geenen analysed the situation around Pacalta's facilities in Ecuador. 'There was a total absence of government support and services. There was a demand for social support outside of a normal oil and gas company's operating mandate.' Rather than take the traditional 'candy and rubber boots' approach, they came up with a different idea. 'Jim and I developed a plan. Let's do a non-paternalistic solution, not based on handouts, but a multi-year, long-term solution.'

Wright went to Pacalta's Board of Directors and proposed a non-profit organisation that would be funded by the company but would develop a social programme independently. The Board agreed and Fundacion de Nan Paz (Foundation of the Road to Peace) was formed. With Geenen at the helm, the foundation tried a host of different initiatives. 'There was a labour company that trained people how to work. They also promoted sustainable forestry, coffee farming in shade, micro-enterprise with the women of the community.'

According to Wright, the plan worked. 'It employed a lot of people and did a lot of good.' Over the course of three years, Pacalta's production in Ecuador went from 4,500 b/d to 45,000 b/d. And, during that time, its installations never came under threat of disruption. 'We had peace in the valley.'

Vredenburg interviewed Wright as part of his research. 'Wright wasn't doing it because he is a bleeding heart liberal. He's a bottom line guy. This is a strategic issue, and he built a legitimate business case for it with his shareholders. It cost around $1mn per year. As far as he was concerned, it was a fraction of what it would cost if they shut down production.'

By managing stakeholder ambiguity, Pacalta engendered sufficient success to become an attractive acquisition target. In 1999 Alberta Energy Company (AEC, which later merged with PanCanadian

Pollution in the rainforest – virginal no longer

to form EnCana Corporation, currently Canada's largest oil and gas company), paid C$1bn to purchase the company.

Wright and other Pacalta executives subsequently invested in a new oil and gas company which eventually became Petrobank. 'Their approach was that they had the level of technology to compete with anyone else, but they also had the above-ground expertise,' says Vredenburg. 'They went out to look for big elephants.' Petrobank's first stop was Colombia. 'There are many complicated and often ambiguous stakeholder groups, such as the Roman Catholic Church, local communities, international NGOs, an influential state oil and gas company and various indigenous communities. In addition, Colombia also suffered from narco-terrorist activities, the Revolutionary Armed Forces of Colombia–Popular Army (FARC-EP) revolutionaries and counter-revolutionaries.'

Petrobank, however, saw an opportunity to re-acquire valuable assets at an attractive price. It purchased from AEC a number of projects and blocks that Pacalta had previously held, including a 15% interest in a field producing 8,000 b/d. 'We have a lot of plans,' says Wright. 'We have a big office in Bogota and the major decisions are made there. There is the potential to create 40mn barrels of reserves for the company.'

The best laid plans...

For those looking for a quick fix, Hall, Vredenburg and Wright take pains to point out that there are no easy solutions to sustainable development issues. 'It's difficult to come up with a checklist,' notes Hall. 'It's very much task based, you need to be in the context. However, because it's so hard, other companies will find it difficult to copy, and may thus be a source of competitive advantage.'

Some nuggets of advice can be gleaned from Wright's and others experience, however. First of all, the decision to pursue strategic advantage through sustainable development must be made by senior management. 'The mindset goes from the top down,' says Wright. 'It permeated our organisation.'

Secondly, the company must have senior management on-site. 'We moved all our key decision makers to Ecuador,' says Wright. 'I lived in Quito. We were fully empowered to make decisions right there.'

Wright recommends that senior executives take time to understand issues from a local perspective. 'Learn the language, understand how the politics and legal systems work.' Then, use that knowledge to advantage. 'Being a small company, we had no policy manual handed down from above, so we could create a made-in-country solution.'

Finally, keep in mind that it may take years for plans to come to fruition. 'Spending $10mn in one year may not be as effective as spending $1mn over 10 years,' notes Hall.

While it may take several years and much effort to develop such skills in-house, once obtained, the world can become your oyster. 'Look at Russia,' says Hall. 'There are all kinds of problems, and all kinds of oil. There are tremendous opportunities.'

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There is good reason, therefore, for the centre to establish common practices, processes and procedures – a task that operating units cannot undertake themselves. Several large players are currently embarked on programmes where the centre has identified a very specific need to play a coordinating, controlling role and have created vehicles for change to meet that need.

In its facilitator role, the centre is the best placed entity to smooth the transfer of best practices, particularly as it remains distanced and independent of the occasional business unit rivalry. That's the *theory* at least. However, for many of those engaged in the *practice*, the reality is somewhat more challenging. Inevitably, we come back to the issue of 'degree' or balance. To what extent does the centre exert influence over its operating units and how does it choose to do so?

Exerting influence

The centre translating innovation and entrepreneurship from one part of the business can lead to enhanced local performance – but it doesn't necessarily follow that other assets will readily take up the ideas. Those who have tried to transfer best practices will identify with an often painful experience – the 'not invented here' syndrome that can breed resentment and risks resistance.

Above all, it is important to remember that neither centralisation nor decentralisation are 'events' or finite achievements in their own right. Each is an ongoing process that requires considerable investment in terms of time and resources.

Centralisation may well achieve a level of consistency, but how then does it manage not to stifle continuous improvement? Processes won't remain static forever – modifications and refinements will inevitably emerge, whether it be due to local requirements, pressure from joint ventures or changes in cultural and operating contexts. In time, creeping change will almost inevitably result in increasing divergence.

A lightness of touch and flexibility of approach may be the key. Some might say that this isn't centralisation in its purest sense. However, like real 'parents', parent companies know to their cost that too much autonomy can carry an expensive price tag. Conversely, they know that just enough independence makes for a successful, imaginative and yet responsible child.

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Russia seeks alternative to Turkish Straits

Russia's Minister of Industry and Energy, Viktor Khristenko, predicts that oil production will total 450mn tonnes by the end-2004, a 7% year-on-year increase, with exports of some 260mn tonnes. Russia's oil exports infrastructure operates with difficulty, but usually without delays. However, if problems do arise, Russian oil workers and transport providers are generally not to blame. One problem is the critical situation caused by congestion in the Turkish Straits. RIA-Novosti Economic Editor *Vasily Zubkov* reports.

The Kremlin, Red Square, Moscow *Photo: Howard Gethin*

Some 135mn tonnes of oil and oil products were exported from Russia via the Black Sea in 2003. However, as volumes increase, so do the number of 'traffic jams' on both sides of the Straits. Freight prices are also rising as a result. Today, one-third of the $19.3 price for transporting a tonne of oil from Novorossiysk to Italian ports is spent on covering the demurrage of tankers waiting to pass through the Bosphorus and the Dardanelles. Russian exporters thus lose $400mn every year. Transit through Turkey has become a bottleneck for Russia's exports, both figuratively and literally.

However, the problem of passing through the Straits is not only due to intensive traffic, but also measures adopted by the local authorities. For example, they have imposed a ban on tankers sailing at night and on the simultaneous passage of more than one tanker in daytime.

Ankara's tougher position on navigation security in the Straits is clear. The Turkish representatives – who recently told Russia's leadership that their country's Straits are not pipelines – know only too well the danger that tankers in the endless line of barges pose for Istanbul, as they pass a few hundred metres away from heavily populated districts. By reducing the Straits' traffic capacity, and thereby averting the possibility of an environmental disaster, the local authorities cause congestion.

Obviously, this 'clot' will not be unblocked in the long term either, even after the Baku-Tbilisi-Ceyhan (BTC) oil pipeline is commissioned. The new pipeline is expected to export tens of millions of tonnes of Azeri oil from new Caspian fields. This oil remains to be extracted, however, and perhaps this uncertainty over the Caspian oil prompted the pipeline's builders to start actively wooing Russia and Kazakhstan with oil, simultaneously restricting the passage of tankers through the Bosphorus?

Seeking a solution

Where might a solution be found? Is there any alternative to the Turkish Straits? State-run Transneft, the leading operator of Russia's main pipeline network, has long been thinking about this issue. Out of several bypass routes for

Russian oil, experts at the Main Pipeline Design Institute in Giprotruboprovod have pointed to two key options:

- the Turkish route – Kiyikoy (the Black Sea) to Ibrihaba (the Aegean Sea), and
- the Bulgarian-Greek route – Burgas to Alexandroupolis.

In May 2004 the Transneft Board approved the company's participation in developing the project on Turkish territory. The project, which includes a 193-km long pipeline with a diameter of 1,220 mm, the main and relay pumping stations, the tank field, end terminals and loading berths, is expected to take two years to complete. Once commissioned, the pipeline will transport some 60mn t/y of oil, assuming 50% of the Bosphorus' load.

The project's designers are counting on the opportunity to service ocean super-tankers with a deadweight of up to 300,000 tonnes and organise massive exports of Russian oil to the US east coast. According to their calculations, oil shipments from the Black Sea ports to Houston will be between 10 and 11 days faster than current export options, while the freight price per tonne will fall by $7. Ocean tankers are currently prohibited from entering the Straits.

Transneft will operate and lay the future pipeline. According to sources in the company, this will be their first experience in this field. A group of Turkish companies, Anadolu, will act as Transneft's partner on the project, and its main investor. So far, the sides have drastic differences over how much the project will cost, with the Russians believing that at least $900mn will be needed. According to Sergei Grigoryev, a Transneft Vice President, the Russian side is fully prepared to implement the project and now the ball is in the Turks' court. Moreover, the participation of Russia's BP-TNK and Tatneft in the Kiyikoy-Ibrihaba project's working group guarantees that the pipeline will be filled.

EU position

At present, the European Union's position is unclear, although Brussels can hardly be very happy that all the three southern oil transit routes – a sea and two land oil pipelines – will come from the former USSR, leaving Ankara holding the 'nuts and bolts'. This is one of the reasons why the EU is lobbying alternative oil shipment projects in the Balkans, which could involve Bulgaria, Romania, Albania, Macedonia, Greece, and Croatia. The completed Odessa-Brody pipeline transitting Ukraine is considered to be another alternative route.

The Burgas-Alexandroupolis pipeline, developed ten years ago, is the most feasible of these projects. Russia's Lukoil, which has considerable interests in Bulgaria and Greece, is actively lobbying for it, while the Russian and Bulgarian Presidents discussed the project's future at a recent meeting. The Bulgarian Government has adopted a decision to launch the project. The third party is Greece, which participates in the project on a parity basis. Although the text of a trilateral government memo on the pipeline has been coordinated, the shares of each of its participants have not been officially registered. Lukoil also believes Greece's transit tariffs to be too high.

If the project is implemented, the 285-km pipeline will transfer up to 40mn tonnes of Russian oil every year. The cost of the project is $700mn, while the recoupment period is seven to ten years, given current oil prices and tariffs.

Evidently, Russian oil has realistic projects for bypassing the Bosphorus, but it remains to start their implementation as soon as possible. Moscow will certainly make every effort to replace the narrow lane of the Turkish Straits with a wide avenue to increase its oil exports.

Meeting challenges in a complex energy market

Speaking at the EI Autumn Lunch held at Claridges Hotel, London, on 20 October 2004, *Jeroen van der Veer*, Chairman of the Committee of Managing Directors, Royal Dutch/Shell Group (above), stressed how important it was for policy makers to ensure that the regulatory framework across Europe is supportive of major long-term investments that will bring the diversity of supply that is key to security of supply. The following are some key highlights of his presentation.*

Jeroen van der Veer opened his keynote address by commenting on the issue of supply versus demand, saying: 'Oil supply is not at capacity – but demand may well be close to it. We need to ensure that we have the capacity to meet future demand, which means investing now for the long-term. And governments will need to facilitate that investment.'

Looking at current demand in more detail, he stated that the industry was in 'an unprecedented situation', having seen this year the biggest annual increase in global oil demand since 1978 – some 3% – more than double the average of recent years. 'It is that which is putting pressure on oil prices at the moment,' he commented.

He continued by stating that, while the situation was understandably attracting a lot of attention from the media and general public, the energy industry had to be careful not to be distracted too much by these immediate pressures, and had to keep its 'focus on the long term'.

'Governments and policy makers, who tend to be driven by the short term, will increasingly need to recognise that if they don't create the environment for long-term energy investment then future prices will be high,' he warned. And the scale of the task ahead is significant, with the International Energy Agency (IEA) estimating that the oil and gas industry will need to invest some $6tn over the period to 2030 if it is to be able to meet future demand. Van der Veer stated that: 'This is achievable, but will require a supportive tax and regulatory framework, and real focus and vision from all those with a stake in the sector.'

Market complexities

Moving to the nature of the 'complex global energy market', van der Veer stated that demand was growing, and growing in new areas of the world – there were new suppliers and even new products such as gas-to-liquids. He indicated that this meant that the energy sector was going through a period of massive change, and that judgements and decisions had to be made in a more uncertain climate – making for a more exciting, but potentially riskier, business environment. It was important to make sure that these risks were managed and adapted successfully to the new environment.

He said that this was particularly true of the UK, where the role of the North Sea in supplying the nation's energy needs is changing, presenting a number of challenges to those working in the energy sector, to policy makers and to consumers. He stressed that Shell did not share the view that the North Sea is rapidly approaching the end of its life.

Wolfgang Schollnberger – former member of the IP Council, recently retired as Technology Vice President, BP, and relocated to Houston where he has been actively supporting the setting up of the EI Houston Branch – accepted an EI Award of Council at the Autumn Lunch. The Award was made for his 'outstanding contribution' to the international oil and gas industry and the work of the EI.

Indeed, Europe and the UK remain very important to Shell's upstream business, with one-third of the group's upstream earnings, production and capital investment coming from Europe.

In 2004 Shell's capital investment in the North Sea as a whole is forecast to reach about £1bn. The group continues to explore in the Atlantic Margin, has secured new licences in Norway and is applying technology to develop and extend the life of marginal fields across the UKCS. Across Europe, the company believes there is at least as much still to produce as has been produced in the past 30 years, while in Norway, the industry has probably produced less than one-third of the available reserves.

Van der Veer explained that Shell was 'not alone' in thinking that there was plenty of value left in the North Sea. Recent UKOOA figures show that the industry plans to invest £18bn in the North Sea in the period to 2010. There has been a record number of new entrants in the latest licensing round, and exploration and appraisal expenditure is likely to rise by 12.5% compared with last year. 'All of these are very positive signs that underline that there is more to come from the North Sea,' he said. He also mentioned that pushing the boundaries of technology would be key to developing future reserves.

Working with the EI

Van der Veer then went on to mention the role that the Energy Institute had played in 'fostering the potential' of the oil and gas industry and in 'driving best practice'. He mentioned one particular initiative – the 'Hearts and Minds toolkit' – which had been developed by Shell and which the Energy Institute is now helping to share more widely (see *Petroleum Review*, November 2004).

This initiative shares best practice on safety. It is a set of materials, developed with input from leading European universities and established psychological research, that provides techniques for changing attitudes to safety in organisations and building a safety culture. 'This is vitally important – prolonging the life of our North Sea assets requires us to work smarter and faster – but we must not lose our focus on the essential task of making that work safer. We hope that this partnership will make a contribution to achieving that end.'

Security of supply

Van der Veer went on to state that: 'Diversity of supply is the key to security of supply', reiterating that what was needed to achieve that diversity was a long-term approach and supportive investment climate. He said that there was some evidence of that happening here in the UK, where action was being taken in a timely way to meet the changing situation, where industry and government are working together to create the climate which will support future investment.

He mentioned the Ormen Lange project – to be operated by Shell from 2007 when production is due to start. This giant gas field is forecast to produce up to 20bn cm/y and has the potential to supply 20% of UK gas needs for 40 years through the 1,200-km Langeled pipeline to Easington. He stated that one of the reasons why the investment in the pipeline had been secured was the progress the UK and Norwegian governments had made towards removing the barriers to cooperation across the North Sea.

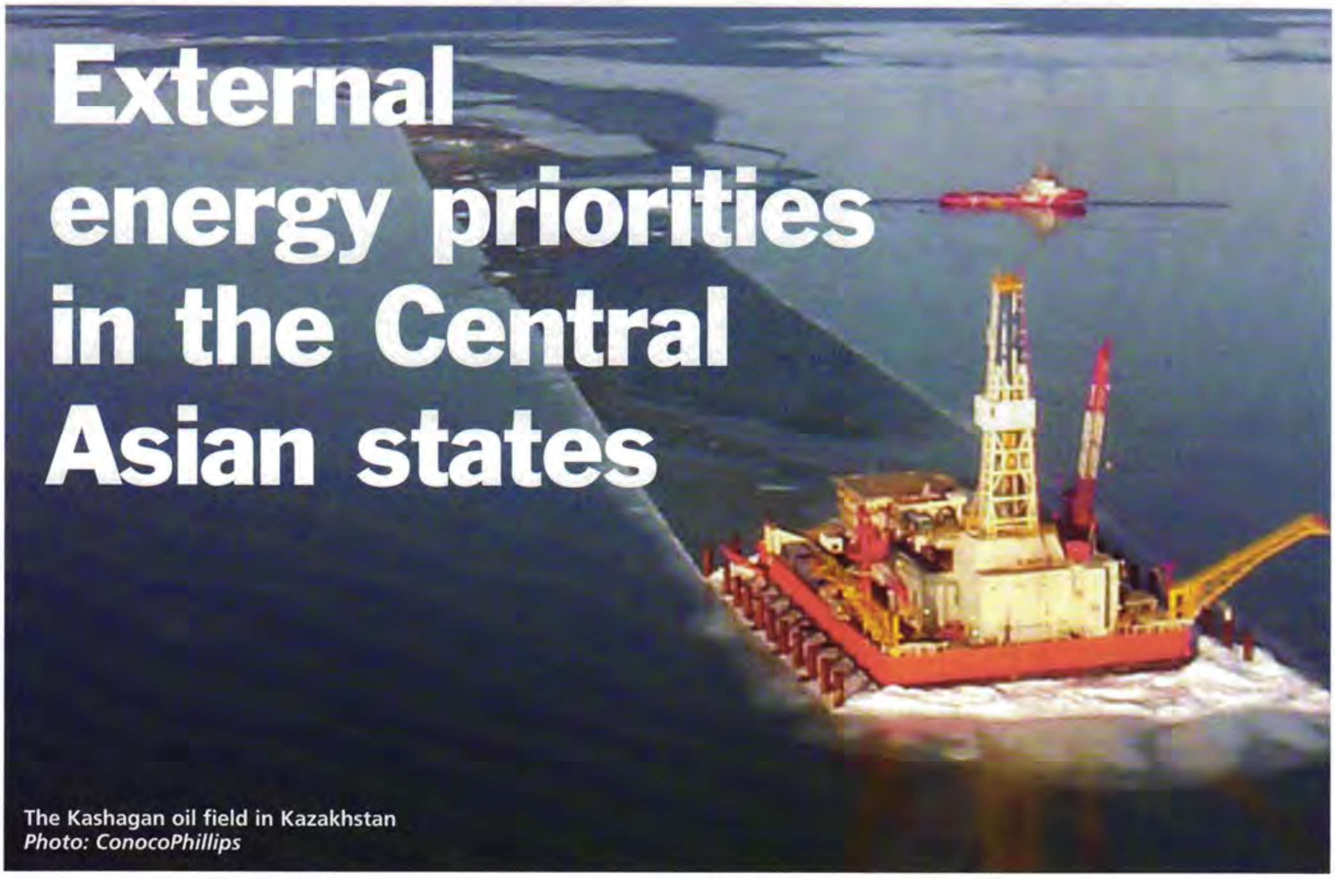
Another important project that will help provide future energy supplies to the UK is the Gasunie BBL pipeline that will run from Balgzand in the Netherlands to Bacton and will have the capacity to supply up to 17bn cm of gas to the UK. This project requires significant capital investment, which carries risks for investors. Van der Veer commented that it had been 'particularly encouraging' that Ofgem had indicated that it was willing to exempt the BBL pipeline from third-party access requirements.

Dr John Lynn, ChevronTexaco Vice President – Marketing Europe, won a bottle of champagne, donated by Claridges, in the EI Autumn Lunch business card draw.

Change and challenge

Concluding his presentation, van der Veer said that there was 'a lot more oil and gas to come'. However, he once again stressed that appropriate regulatory frameworks and tax systems needed to be in place and that new technologies would be key to future developments meeting the demands of an increasingly complex market.

A full presentation based on Jeroen van der Veer's speech at the EI Autumn Lunch can be found at* **www.shell.com



External energy priorities in the Central Asian states

The Kashagan oil field in Kazakhstan
Photo: ConocoPhillips

Dr Malika Saidkhodjaeva, Consultant, The World Bank Country Office, Tashkent, Uzbekistan, reviews the current energy position and prospects of the five Central Asian States (CAS), which are energy-rich with high export potential. The article focuses firstly on the countries' current and prospective interdependence. It then examines their wider opportunities within an expanded Euro-Asian energy market.

The five Central Asian States (CAS) of Kazakhstan – the Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan have a total population of some 56mn spread thinly over a vast area of 4.35mn sq km – 12 times the size of Japan, which has three times the population. Kazakhstan, for example, has a population density of just 10/sq km and Uzbekistan of 60/sq km, compared with 386/sq km in China and 315/sq km in India.

This relatively small and divided market is thus faced with very long distances between concentrations of population and very high oil and gas transportation and electricity transmission costs. The area is completely land-locked and is dependent on neighbouring countries and other transit countries for access to hard-currency markets.

The Central Asian States are rich in fossil fuel energy – tapped by successive coordinated development plans of the Former Soviet Union (FSU) with a marked orientation towards Russia. Since independence, however, the five states have all struggled hard to adapt this integrated system to meet their own national needs and have had to dispose of energy surpluses as best they can.

Kazakhstan has been the most successful in attracting external capital and technology, as well as finding new external markets. Turkmenistan has also been successful in identifying external demand and supplying gas to meet that demand. The hydro-rich countries of the Kyrgyz Republic and Tajikistan have been able to export some of their surplus of hydroelectricity. While Uzbekistan has limited potential to export additional volumes of oil and coal, it does have major opportunities to increase its exports of gas if pipeline capacity is available and forthcoming.

Export/import potential

The following paragraphs examine in more detail the export and import potential of the five states.

Kazakhstan

Kazakhstan has significant petroleum reserves that are estimated at 0.8–2.5bn tonnes.

Oil production in 2003 was 52.2mn tonnes, double the level in 1998 and rising strongly, with consumption of 9.5mn tonnes. The growth of exports is hindered by a lack of pipeline capacity and the long distances to markets. However, Kazakhstan took a major step towards increasing oil exports with the launch of the 990-mile long Caspian Pipeline Consortium (CPC) pipeline in 2001, which allows the direct transport of oil from the Tengiz field to Russia's Black Sea port of Novorossiysk.

Proven natural gas reserves of 1.9tn cm at end-2003 are located mainly in the Kashagan, Karachaganak and Tengiz fields. Kazakhstan is among the top 20 gas reserve countries of the world.

Production reached 12.9bn cm in 2003, but much gas is flared during oil production. The lack of internal pipelines is such that the Kazakh industrial belt depends on imports of Uzbeki gas and some Russian gas. In 2001 Kaztransgaz and Uztransgas entered into a five-year gas supply agreement, with Kazakhstan purchasing 1.7bn cm of gas in 2002.

Kazakh coal reserves are estimated at 3.4bn tonnes, some 3.5% of the global total. Production in 2003 was 43.2mn tonnes and consumption 26.9mn tonnes, with exports to Russia, Ukraine, the Kyrgyz Republic and Uzbekistan. Plans to sell coal to Turkey and Iran are dependent on improved transportation links.

Uzbekistan

Uzbekistan has significant oil, coal and natural gas reserves. Its only current crude export option is to reverse an existing pipeline that brings Russian oil to Uzbek refineries. However, the relatively small surplus of oil available for export does not merit the construction of long export pipelines.

Uzbekistan is one of the top ten gas-producing countries in the world, producing 53.6bn cm in 2003 and consuming 47.2bn cm. Exports of gas have recently declined on account of non-payment and other delivery problems. Gas reserves are ample – in addition to limited exports to Kazakhstan, the Kyrgyz Republic, Russia and Tajikistan via the Central Asia-Central Russia pipeline, Uzbekistan hopes to secure an extension to the Trans Caspian gas pipeline for exports to Europe.

Uzbekistan also plans to expand its modest coal production to keep up with domestic demand and produce a small surplus for export.

Kyrgyz Republic

Hydroelectricity export potential in the Kyrgyz Republic is enormous. Primary electricity production from hydropower accounts for more than 80% of total primary energy production and could be expanded ten times its current level.

There are also significant reserves of brown coal, although production has declined to negligible levels. Imported coal is used to fire the country's largest thermal power plant in Bishkek.

There is minimal oil and natural gas production, necessitating limited imports of oil, natural gas and coal.

Tajikistan

Tajikistan also has vast hydroelectricity export potential – as yet untapped. The country has a very small oil industry and no refineries. It is dependent on oil imports from Uzbekistan and gas imports from there also, and Turkmenistan. Coal production and consumption has collapsed over the past decade.

Karachaganak gas field – Kazakhstan
Photo: www.eni.it

Turkmenistan

The primary energy reserves of Turkmenistan consist mainly of natural gas – production has been rising steeply, reaching 55.1bn cm in 2003, with roughly 36bn cm exported to Russia and small volumes to Ukraine and Iran. Further export hopes are being focused on the Trans Caspian gas pipeline project which would run from Turkmenistan, under the Caspian Sea and through Georgia to Turkey.

Electricity grid and exports

The electricity grids of the Kyrgyz Republic, Tajikistan, Uzbekistan, south Kazakhstan and Turkmenistan all belong to the integrated system known as the Central Asian Power System that was installed by the Former Soviet Union (the USSR at the time) and it still operated synchronously by its successor, the Central Asian fPower Council. Central dispatch is handled from the nerve-centre of the system in Tashkent, Uzbekistan.

Uzbekistan generates 52% of the total power in the system, Tajikistan 16%, the Kyrgyz Republic 15%, Turkmenistan 11% and south Kazakhstan 6%. Since 1990 there has been a marked decline in electricity consumption throughout the area. The volume of power exchanges between these states declined by 70% between 1990 and 2000 as each state pursued energy self-sufficiency policies and many payments for imported electricity were suspended, resulting in the cutting of further supply.

The 2004 World Bank Report on Energy in the Central Asian States identifies three potential major electricity export routes out of the integrated Central Asian Power System and one separate route from eastern Kazakhstan:

- west through Afghanistan (Herat) to Iran (Mashad),
- south through Afghanistan (Kabul and Kandahar) to South Pakistan (Karachi),
- east from Kabul to northern Pakistan (Islamabad and Tarbela),
- eastwards from north Kazakhstan (Almaty) to China (Urumqui).

Oil and gas exports

The current projects to carry Caspian and Central Asian oil and gas to China and Western Europe have been matched by even more ambitious plans to carry Central Asian gas through Afghanistan or Iran to Pakistan and India, and to build new gas pipelines to link Middle East Gulf suppliers to southern Russia through Iran.

Progress is likely to be slow, but once such a system is in place the value of the largely stranded hydrocarbon resources of Central Asia will increase immeasurably and development will be accelerated. Indeed, in such an integrated Euro-Asian oil and gas system, the Central Asian states would be at, or close to, the centre or hub of the system and would derive major economic benefit from that proximity.

However, in the short term, regional development of oil and gas will almost certainly be led by Kazakhstan – although proposals for the wider network will have substantial impacts on all five states.

EI technical programme – a very busy year

The past year – 2004 – has been another active one for the EI's Technical team. On the right is a list of some of the main projects that the team has been progressing during the course of the year writes *Lawrence Slade*, EI Business Development and Technical Director.

- Field trial to confirm the cause of aviation fuel filter monitor water removal performance degradation D
- Clarification of acceptable loading limits for aircraft fuel adaptors D
- Revision of APEA/IP Guidance for the design, construction, modification and maintenance of petrol filling stations D
- Technical support for 2nd edition of Area Classification Code (IP15) C
- Improving manual handling in product distribution and aviation fuel handling D
- Avoiding human error in product distribution D
- Review of carbon monoxide (CO) monitors for rapid detection of hot spots in VRU (vapour recovery unit) carbon beds D
- Preparation of guidance on the implementation of ATEX requirements at terminals D
- Consultancy fees in support of EI's 2004 work programme on health C
- New practical human factors tools for major hazard installations C
- Factors affecting nitrite production associated with nitrate treatment U
- New 'Upstream technical safety guidance framework' U
- Epidemiology database maintenance C
- Critique of the forthcoming COMEAP report on a threshold level of ozone for air quality D
- Scoping study of refinery emissions of dioxin in the UK D
- Electrostatic properties of personal protective equipment (PPE) at distribution facilities D
- Investigation into the 'negligible risk' of electrical equipment operated by small batteries, eg those used in hearing aids D
- Mapping of ecologically sensitive sites for national contingency planning C
- Development and revision of existing guidelines and codes of practice for hydrocarbon management in offshore locations, marine and terrestrial transportation, refineries and marketing and distribution operations C
- Very heavy fuel oil risk assessment C
- Verification of lightning protection requirements for above ground hydrocarbon storage tanks – experimental study D
- Hydrocarbon remediation by photo catalysis D
- Development of new and the revision of existing standard test methods to requirements of aviation, automotive and marine fuel specifications, HSE and HMC&E requirements and to take advantage of new technologies. C

Key: C = Cross Sector D = Downstream only U = Upstream only

These projects form part of the core activities of the secretariat in supporting our members and promoting the self regulation of the oil and gas industry in the UK. This varied workload includes the updating and maintenance of more than 250 codes and guidelines published by the Energy Institute.

The value of the EI's Technical Programme has been demonstrated via an independent analysis of projects carried out over a two-year time frame. This report indicated gross savings to industry in excess of £40mn from an investment of under £2mn.

Industry cooperation

Many of the projects that the EI undertakes are done so in cooperation with a number of other bodies to ensure the fullest applicability of the project deliverables and relevance to legislative issues.

An example of this is the *Protocol for the determination of the speciation of hydrocarbon emissions from oil refineries* – a joint Energy Institute and Environment Agency document produced by the National Physical Laboratory (NPL) under the guidance of the EI's Emissions Working Group and representatives from the Environment Agency for England and Wales.

This particular protocol was produced in cooperation with UKPIA's Refinery Emissions Working Group (WG15) and provides a methodology for determining the fractional speciation of hydrocarbon emissions from oil refineries. It was developed and validated during a series of measurement campaigns conducted at two UK oil refineries, under summer and winter conditions. These trials demonstrated that the approach contained in the protocol provides a cost effective and robust methodology that will be incorporated by the Environment Agency into future operating licence conditions for the oil refineries.

Extensive cross sector support

The EI's Technical Programme is developed in partnership with, and funded by, the following EI Partner companies – BP, Shell, ExxonMobil, ChevronTexaco, ConocoPhillips, Eni, BG Group, Talisman, BHP Billiton, Encana, Murphy Petroleum, Kuwait Petroleum Research and Development, Kerr-McGee North Sea, Statoil and Total.

In addition to the funds received from these bodies, support is also provided from a diverse range of government and commercial entities that, in 2004, has included the DTI, MCA, Environment Agency, English Nature and United Airlines. In some cases, such as with the Aviation Fuel Filtration Project (*Petroleum Review*, October 2004), over 50% of project funds have been received from third parties. In total, the funding received for specific industry projects in 2004 exceeded £700,000.

New Upstreamer

The team at the EI was added to in the second quarter with the appointment of Keith Hart as Upstream Technical Manager, based in Aberdeen. Keith is responsible for maintaining and building the EI's influence and relationship with our upstream industry partners.

Individual investment

The success and value to industry of the EI's Technical Programme would, of course, not be possible without the input and investment in time of all the volunteers from oil companies, contractors, government and trade organisations.

As 2004 draws to a close it seems appropriate to end with a vote of thanks to them all for their efforts, as we look forward to what promises to be another busy technical year in 2005!

EI/IFIA Petroleum Inspector Certification Examinations

The first examinations outside of the UK were held in Rotterdam on the 20 and 21 October with over 100 candidates from a number of inspection companies sitting the examinations.

The venue for the examination was kindly supplied by Shell Nederland Raffinaderij B.V. at the Pernis Refinery's Training Centre.

The examination venue was first class as were the arrangements for getting the candidates to and from the Training Centre and the EI would like to take this opportunity of thanking Shell Nederland Raffinaderij B.V. and in particular Captain Hans Ammerlann for all the work that went into making the examinations a success.

More examinations are planed for locations within and outside the UK in 2005 and details of the dates and venues will be published in the near future.

Multi-elemental bench top analyser

Thermo Electron recently unveiled its multi-elemental bench top SphiNCX analyser for fast, reliable and sensitive analysis of total sulphur (TS), total nitrogen (TN), total organic carbon (TOC) and total organic halogens (AOX/TX).

The four-in-one configuration unit offers high and low measuring ranges in a wide variety of sample types, and is claimed to be ideal for controlling ultra-low levels of sulphur, preventing contamination in fuel cells.

The analyser incorporates and is compatible with the multifunctional NeXYZ auto sampler – reportedly the first of its kind for solids, small volume hydrocarbons, large volume water samples and headspace analysis. 'The SphiNCX's exchangeable sample tray and pick up heads ensure flexible, fast and easy sample introduction,' states the manufacturer. 'The NeXYZ works around the clock, guaranteeing higher throughput and resulting in low cost analysis.'

e: **analyze@thermo.com**
www.thermo.com/elemental

Monitor gas and fire hazards at a glance

Crowcon's new wall-mounted Gasmaster control panel displays all gas levels simultaneously on a large, multilingual LED display, allowing full system checks at a glance. It can monitor up to four channels, with two levels of alarm per channel, allowing it to monitor virtually any combination of flammable and toxic gas detectors, oxygen detectors and fire detectors (smoke, heat or flame).

All functions, from day-to-day operation to recalibration are done on the front panel, so routine testing can be carried out in an instant. The device also warns when calibration is due and all inputs and outputs can be quickly tested at the push of a button. All alarms and faults are recorded in an 'event log'.

Relays can operation in 'fail-safe' mode and all coils are actively monitored so Gasmaster can warn if a relay fails. Installation and maintenance is reported to be simple, with ample space for cable glands and termination of wiring.

t: +44 (0)1235 557700
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Modular interlocks

Industrial safety specialist Fortress Interlocks has extended its range of mGard trapped key safety interlocks. The company's range of modular door locks, bolt locks and key exchange units now come complete with rotary switches for power or control isolation.

The mGard range consists of robust modular units, which control access to enclosed areas. Available in one to ten-module versions, Fortress offers a patented sequencing system with up to 39,000 different sequences in a ten-module arrangement. Simple to configure, the units can be easily extended, or trimmed down and the surplus modules used elsewhere.

The company's door module, bolt module and key exchange module are all now available with 20A, 32A, 63A or 150A rotary switches. When a key is inserted and turned, the contacts on the switch are changed. The modules can therefore be used to isolate power, controlling access to potentially hazardous areas until a safe condition has been achieved.

The mGard modules feature a slim, die-cast zinc body with pearl bronze finish. The internal contact components and keys are constructed using stainless steel. Fully stainless steel versions of the modules are also available. There are four mounting options – panel, enclosure, back of board and concealed. Within a modular arrangement the 20A and 32 A switches may be fitted behind each lock.

t: +44 (0)1902 499600
f: +44 (0)1902 499610
*e: **sales@fortress-interlocks.co.uk***
www.fortressinterlocks.com

New compression tube fittings offer tenfold time savings

Parker Instrumentation has completed its family of rapid-assembly 1,034 bar (15,000 psi) compression tube fittings with the release of 15 new component shapes. The company claims it can now offer 'flow arrangements providing an efficient single-piece solution for virtually every common connection requirement'.

Using the industry-standard compression sealing technique – which assembles in seconds by simply tightening a nut – Parker's new MPI fittings are reported to save an estimated 20 minutes at least per connection. The new fittings are also claimed to be resistant to vibration, eliminating the additional cost of the vibration gland that is commonly used with cone-and-thread fittings.

t: +44 (0)1271 313131
f: +44 (0)1271 373636
www.parker.com

Compact breathing apparatus with maximum versatility

Ergonomically designed to follow the natural contours of the back and improve wearer comfort, the new lightweight Draeger Personal Airline System (PAS) Micro is claimed to be ideal for use in applications requiring either a short duration entry unit, airline emergency escape breathing apparatus, or dual function unit.

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NEW Publications

Trends in Oil Discharged with Aqueous Effluents from Refineries in Europe*

(Concawe, Boulevard du Souverain 165, B-1160 Brussels, Belgium. t: +32 2 566 91 60; f: +32 2 566 91 81; e: **info@concawe.be***). 10 pages. Available as free downloads from* **www.concawe.be**

This report summarises the information gathered by Concawe in a survey of Western European oil refineries' effluent water quantity, oil content and treatment processes in 2000. It compares the data with the results of previous surveys and shows that the trend in the reduction of oil discharges has continued – falling by some 36% between 1997 and 2000. The ratio of oil discharged to the amount of oil processed has also continued to fall.

Green Trading™: Commercial Opportunities for the Environment

Editors: Peter C Fusaro and Marion Yuen (Green Trading, 268 Berkeley Place, Brooklyn, NY 11217–3937, US. t: +1 (718) 230 5402; f: +1 (718) 230 4798; e: **myuen@greentrading.biz**; **www.GreenTrading.biz***). ISBN 0 9745391 0 4. 208 pages. Price: $50 (plus $5 shipping and handling in US, $10 outside US).*

This publication, co-sponsored by DNV and GE Power Systems, takes a closer look at the current state of green trading – encompassing emissions, renewable and energy efficiency financial trading – and the direction of market development over the next few years. Ten chapters of the book are based on presentations given at the Second Annual Green Trading Summit™, entitled 'Emissions, Renewables & Negawatts', held on 7–8 April 2003 in New York.

Economics of Petroleum Production*

Ian Lerche and Sheila Noeth (Multi-Science Publishing, 5 Wates Way, Brentwood, Essex CM15 9TB, UK. t: +44 (0)1277 224632; f: +44 (0)1277 223453; e: **mscience@globalnet.co.uk**; **www.multi-science.co.uk***). Volume 1: ISBN 0 906522 23 4; Volume 2: ISBN 0 906522 24 2. Volume 1: 340 pages; Volume 2: approx. 290 pages. Price: £62 per volume.*

Concerned with hydrocarbon production economics, these two volumes dissect the old adage in the oil industry that exploration for hydrocarbons loses money while their production makes money. Issues explored include how risk should be managed and how a given situation can be analysed so that the chances of obtaining the desired level of profit can be maximised.

Well Seismic Surveying

J L Mari and F Coppens (Editions Technip, 27 rue Ginoux, 75737 Paris Cedex 15, France. t: +33 (0)1 45 78 33 80; f: +33 (0)1 45 75 37 11; e: **info@editionstechnip.com**; **www.editionstechnip.com***). ISBN 2 7108 0776 9. 256 pages. Price (hardback): e90; $90.*

This book summarises the practical features of the well seismic method, providing the reader with comprehensive information on the implementation, processing, interpretation and main applications of this technique. Numerous illustrations help the reader develop a critical view regarding the merits of the well survey, as well as its contribution to the description of geological structures and to the knowledge of reservoirs. With its many animations, the CD-Rom that accompanies the book enables the reader to visualise phenomena, making them easier to understand.

* *Held in EI Library*

World LNG to 2020: Prospects for Trade & Shipping

(Ocean Shipping Consultants, Ocean House, 60 Guildford Street, Chertsey, Surrey KT16 9BE, UK. t: +44 (0)1932 560332; f: +44 (0)1932 567084; e: **info@osclimited.com**; **www.osclimited.com***). Price: Printed version – £850 (UK), $1,600 (including airmail and packaging); Electronic version £850, $1,600; Printed and electronic versions – £975, $1,850.*

The world LNG industry is currently going through a period of massive expansion and change, with trade volumes forecast to increase by a massive 71% by 2010 and 172% by 2020. This report examines the current and historical development of LNG trade, detailing developments by major importer and exporter. By examining the prospects for individual LNG suppliers and import markets under alternative forward scenarios, detailed analysis is included on future prospects for LNG trade volume and structure through to 2020. This is translated into the projected number of extra LNG carriers required throughout the period. The analysis is widened through consideration of likely developments in other aspects of LNG shipping – including vessel technical developments, shipyard activity, LNG spot market development, and the potential for LNG alternatives such as CNG. The report also includes analysis of some 'Worst Case' scenarios – providing an indication of the potential full market implications of sudden disruptions to LNG supply or to LNG imports.

New stock in EI Library

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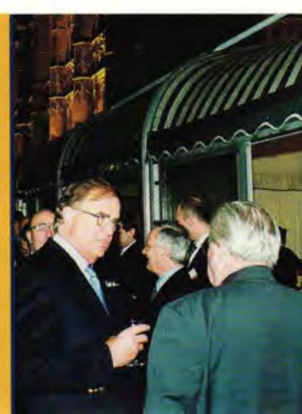

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