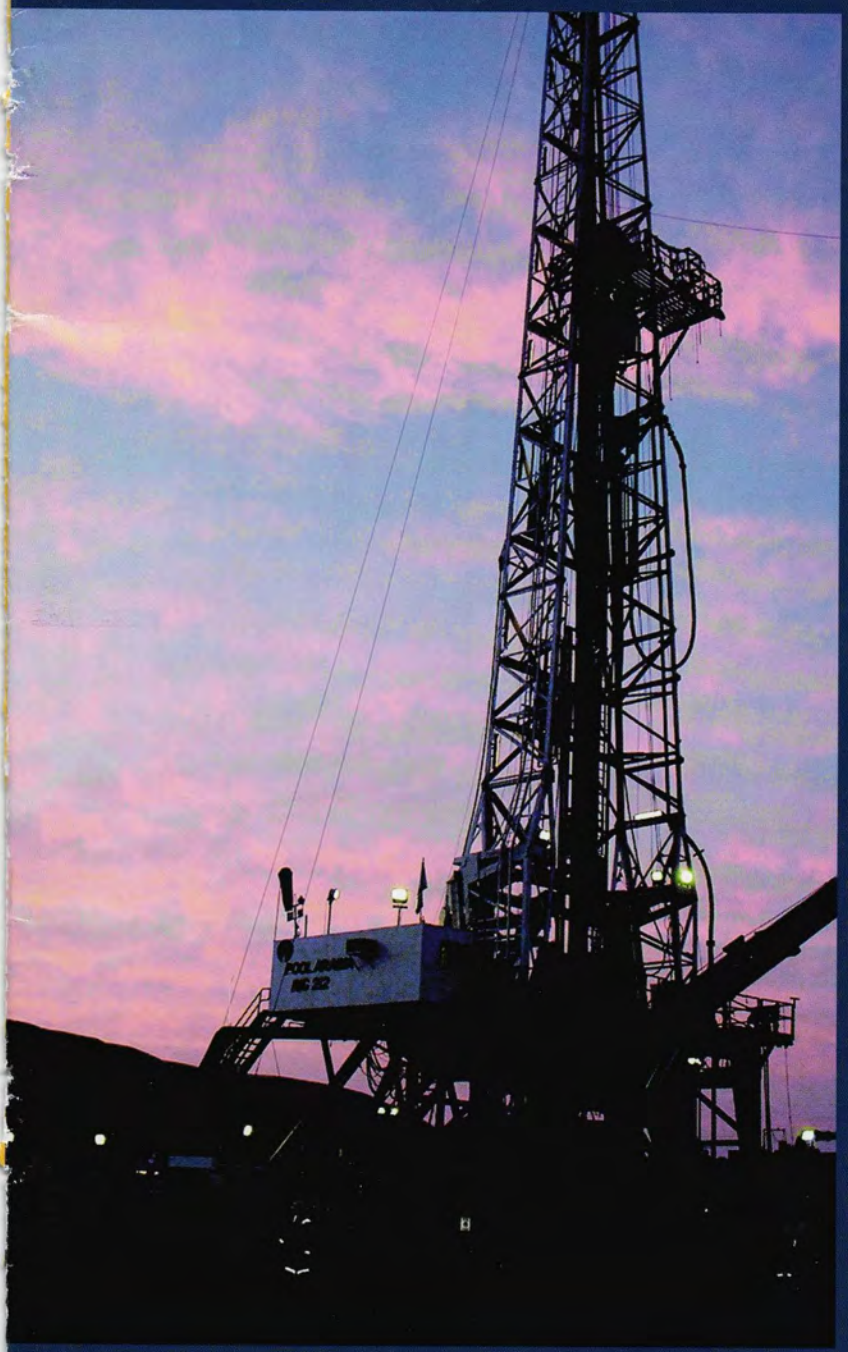
Petroleum review

JUNE 2004



Trading

- Looking forward to project financing

Offshore technology

- Drilling to the max

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- Pipe dream snuffed out
- Mexican oil and politics don't mix

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Wednesday 14 July 2004
Savoy Place, London

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Sir John Mogg KCMG, Chairman, Ofgem (right)

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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
t/y	= tonnes/year	b/d	= barrels/day
		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: Modern drilling technology is now allowing field operators to create production wells with immense exposure to pay zones (see p12)
Photo: WellDynamics

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ROUNDUP From the Editor

Could $40/b oil really be here to stay?

Whenever there is widespread agreement on a subject it is always wise to ask 'Could the conclusion be wrong?' So, could the current view that high oil prices are here to stay be wrong? At the moment oil prices are excessively firm – nearly $42/b for WTI and over $38/b for Brent. In fact, prices are at their highest levels in real terms since the short-lived price spike during the first Gulf War (1990/1991) and the Opec glory years between 1974 and the 1985 price collapse. Before that you have to go back to the Pennsylvania oil boom of 1863–1877 for such high prices. So, if prices are at crisis levels, do we have a crisis?

The cautious answer is probably not. The caution comes because the world is now engaged in a race between the supply enhancing and demand depressing effects of higher prices on the one side, and the momentum of global economic recovery on the other. The 'wild card' is the security situation in the Middle East and the possibility of a cut-off of Iraqi supplies, or even political upheaval and supply disruptions in Saudia Arabia.

The key price driver is rapidly expanding demand caused by a near-synchronous recovery in economic activity in much, if not most, of the world. Led by booming demand in China, currently running 1mn b/d above year earlier levels, extra requirements for crude and products are leading the IEA to revise its demand figures upwards virtually every month. The May edition of its *Oil Market Report* now pegs global demand growth in 2004 at a staggering 1.95mn b/d, the fastest demand growth since 1988.

On the supply side, non-Opec production appears to be flat out with this year's capacity expansions virtually all grouped into the third and fourth quarters. In fact, project slippage means that little new capacity of any size has come onstream so far this year. The latest IEA estimate for incremental non-Opec production in 2004 has been revised down to 1.2mn b/d, from an earlier 1.35mn b/d.

The evidence from the April production figures strongly suggests that the Opec cut-backs amounted to 415,000 b/d and were largely confined to Saudi Arabia (–160,000 b/d) and the UAE (–150,000 b/d).

It is already looking as though the Opec cut-backs will be reversed by the end of May, but any price-depressing effects are likely to be muted. The reversal of the Opec output cuts would then take us back to the situation where the only plausible spare capacity would be in Saudi Arabia and possibly a little in the UAE. [Notional spare capacity in Nigeria is probably not accessible as a result of ethnic and religious tensions and disturbances, while Venezuelan instability and a failure to rebuild its capacity probably means its spare capacity is also notional.]

Much confusion is caused by focusing on Opec quotas, quota cheating and the like. Looking at total Opec production (crude and NGLs) we find the first quarter averaged 31.95mn b/d, reaching 32.22mn b/d in March and dipping to 31.81mn b/d in April. The last time Opec production was running at levels even approaching these was in 1973 and 1979 – the years of the first and second oil crises.

Perhaps the single most important question in terms of future oil supply is Saudi Arabia's ability to maintain, and possibly expand, high volume flows from ageing giants like Ghawar and Safaniya. A radical new development system called maximum reservoir contact, or MRC, is being used and refined in Saudi (see p12). Long horizontal wells are drilled across the top of the reservoir, with additional multilateral wells branching off from them giving drainage rather like a shallow-rooted tree. The full length in contact with the reservoir is open hole and allows very high production rates (up to 20,000 b/d in the Saudi case). The technique, while not suitable for all reservoirs, offers the possibility of large volume flows late in a field's life. It may prove to be a key technology as the industry seeks to maximise flows from mature fields.

Between the second and fourth quarters oil demand increased by 3.8mn b/d in 2002 and by 4.8mn b/d in 2003. The IEA estimates the 2004 increase will be 3.8mn b/d – a figure that is dangerously close to all the world's spare capacity and all the new capacity coming onstream combined. Crisis may be too strong a term, but a huge challenge is ahead if oil prices are not to soar.

Chris Skrebowski

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

eworld

The UK Department of Trade and Industry (DTI) recently published a report entitled *Implementing a Demonstration of Enhanced Oil Recovery (EOR) Using Carbon Dioxide*, fulfilling the DTI's commitment in the Energy White Paper to 'set up an urgent detailed implementation plan with developers, generators and the oil producers to establish what needs to be done to get a demonstration [of EOR] project off the ground'. The full report is available at **www.dti.gov.uk/energy/coal/cfft/index.shtml**

The Industry Technology Facilitator recently launched a new website as a further tool to promote the visibility of innovative oilfield ready technology innovations. The Oilfield-Ready Technology website (**www.oilfield-readytechnology.info**) is an important collection point for information about new and innovative oilfield-ready technology. It is focused on technologies that have been developed to the point that they are ready to use in an oilfield environment. The site will assist in matching these technologies with the needs of operating companies.

The European Commission recently presented at the 'Solar platform' test site in Almeria, Spain, the state of play on its research programmes in alternative energy sources. The projects showcased at the presentation included 'European Hot Dry Rock' using geothermal energy (visit **www.soultz.net** for details), 'Wave Dragon' which uses wave energy (visit **www.wavedragon.net**), and 'Sol Air' using solar thermal (visit **www.psa.es/webeng/index.html** and **www.solucar.es/english/index.html**).

The Drilling Research Institute (DRI) has launched a new, free online database of people and companies in the international drilling industry. The 'Energy Industries People [Find People]' and 'Energy Industries Companies [Find Companies]' online directories can be found at **www.drillers.com** The Find Companies index is a comprehensive company directory offering the contact details of a wide range of oil and gas product and service providers. The Find People directory contains individual contact listings for energy, oil and gas personnel. DRI provides oilfield consultancy and training services. The company website also supports the sale and regular updates of the 'Drilling Reference and Training Manual' CD, as well as day rate advice and classified listings.

The Intertanko Annual Review and Report 2003 is now available as an e-book at **www.intertanko.com/about/annualreports/2003/**

In Brief

UK

Amec has won an engineering services *contract from Venture Production for the topside works associated with the development of the Annabel field in block 48/10a in the southern sector of the North Sea.*

Dana Petroleum (12.4%) reports that *work has started on the Banff field gas reinjection project in the UK sector of the North Sea that is forecast to increase remaining Banff oil reserves by 20–25mn barrels and increase field life by up to eight years. Dana's partner and field operator is CNR International (87.6%).*

Douglas-Westwood has now officially *launched 'The World Wave and Tidal Database', an online data source for the rapidly developing wave and tidal industries. For more details, visit* **www.dw-1.com**

Talisman Energy has completed the *acquisition of the Flotta Catchment Area (FCA) interests of Intrepid Energy for $137.5mn.*

Europe

A charter worth around NKr340mn *covering use of the* Eirik Raude *drilling rig in the Barents Sea has been awarded by Statoil to owner Ocean Rig. Statoil plans to operate one well each in areas G and F, while Norsk Hydro intends to drill one in area C.*

Work has started on the F16-E gas field *development offshore the Netherlands. The development will involve a total of five wells producing via a new steel platform and pipeline tied into the NGT trunk pipeline to Uithuizen in the Netherlands. First gas is expected in January 2006, at an initial rate of 150mn cf/d. Proven and probable reserves are put at 450bn cf of gas.*

TGS-Nopec Geophysical Company has *commenced a new 25,000 km multi-client 2D seismic programme in the North Sea. The programme, known as North Sea Renaissance (NSR), is part of a plan to cover the entire North Sea with over 100,000 km of long-offset 2D seismic data.*

North America

ExxonMobil and TransCanada PipeLines *report that they have 'successfully*

NEWS Upstream

Continued global demand for FPSs

Some 120 floating production systems are forecast to be installed over the next five years, involving capital expenditure of $32bn, according to the new fourth edition of *The World Floating Production Report* from energy analyst Douglas-Westwood.

Annual capital expenditure on floating production systems is set to exceed $8bn, with a predicted 84 FPSOs accounting for some 68% of investment over the next five years. The overall picture is one of strong market growth from 2004 onwards, with annual global expenditure in the FPS sector rising from an estimated $4.8bn in 2004 to reach $7.8bn in 2008. An expenditure peak is expected in 2007, when the annual spend is expected to reach $8.3bn.

In terms of the total market, and counting floaters of all types, the reports forecasts West African expenditure to lead at some $10bn over the next five years. Although Brazil will see a strong surge in investment, North America will also see good growth and is likely to be in second place with a forecast spend of over $7bn.

The other main characteristic of the market will be the continuing shift to deepwater, with some 70% of the global spend expected to be on floaters moored in water depths of 500 metres or greater. Over the past five years the deepwater market was dominated by the US Gulf of Mexico and Brazil, which together accounted for over 75% of the total spend. However, the market distribution for the 2004–2008 period is markedly different, the main change being the high growth in the value of deepwater activity off the west coast of Africa. Douglas-Westwood forecasts capex of $8.5bn associated with deepwater FPS installations there, making the region the world's leading deepwater FPS theatre. All the other regions will also see increases in deepwater FPS activity, with North America's spend rising to $7bn (31% of the global deepwater total), and Latin America's to $4.9bn. Australia looks set to see its first deepwater deployment, with Woodside's Enfield FPSO installation forecast for 2006. Off Asia a total of nine installations – five TLPs, two spars, a barge and a FPSO – are forecast with a total capex of $1.7bn.

For the first time, *The World Floating Production Report* uses information from 'The World Floating Production Database', a new information system from Douglas-Westwood. According to Database Editor, Georgie MacFarlan: 'Over the next five years we expect just 12 operators to account for 60% of the installations and almost 80% of the capex forecast worldwide for the 2004–2008 period. Petrobras, with 13 installations forecast, is expected to be the biggest spender, followed closely by ExxonMobil, then ChevronTexaco, BP and Shell.'

Norwegian production and investment levels

The Norwegian Ministry of Petroleum and Energy estimates that average production of Norwegian crude oil (including NGLs) will be 3.2mn b/d in 2004, approximately the same as last year. Output is expected to stay at this level for the next few years, followed by a gradual decline. Gas sales in 2004 are estimated to reach 75bn cm, slightly up from 73.4bn cm in 2003. Gas sales are expected to increase towards a long-term level of 120bn cm/y from 2010.

Investments in 2004 are estimated at NKr71bn, up by more than 10% from 2003 (investments in exploration are not included). The high investment level is to a large extent due to the Ormen Lange project, states the Ministry, which was approved by the Storting this spring and will start investments this year. In addition, the Snøhvit and Kristin fields, both under development, are large contributors to the high investment level.

Over the next few years, investment is expected to remain at a high level, reaching almost NKr300bn for the period 2004–2008 due to expectations of higher gas sales, more new projects starting up, and more projects related to increased oil recovery.

Sakhalin reschedules pipeline to protect whales

Sakhalin Energy has announced that it is to reschedule offshore pipelines construction work in the Piltun-Astokhskoye field pending further technical work that is designed to ensure minimal disturbance to the Western Gray Whale, a critically endangered species. Offshore pipeline construction work during 2004 will now be focused on the Lunskoye field and Aniva Bay further south, previously planned for completion later in the construction period.

The rescheduling of this offshore construction work will not affect the overall project schedule. First LNG deliveries to customers are slated for 2007.

NEWS Upstream

Atlantic and Cromarty processing deal

Amerada Hess and BG Group have finalised the arrangements governing the development of the Atlantic and Cromarty North Sea gas and condensate fields, having recently received the Design Basis Memorandum from ExxonMobil confirming the use of the SAGE terminal at St Fergus for processing reservoir fluids exported from the fields.

The Atlantic field lies in licence block 14/26a and is operated by BG (75%). The Cromarty field lies in licence block 13/30a and is operated by Amerada Hess (90%). The respective operators' estimates of gross recoverable reserves are 118bn cf for Atlantic and 106bn cf for Cromarty.

The total investment, including spend to date, is expected to be around £205mn. First production is scheduled for late 2005/early 2006, and the anticipated plateau rate is 220mn cf/d.

The development will be exploited using subsea technology with production from the two fields being mixed together offshore and exported to gas and liquid processing facilities at the SAGE terminal, operated by Mobil North Sea (an ExxonMobil subsidiary) at St Fergus. The subsea facilities will be operated remotely from the SAGE terminal via satellite link to the Goldeneye platform, operated by Shell, and then via a 32-km subsea umbilical to the Atlantic and Cromarty fields.

Drilling of the development wells is planned to begin in March 2005, and is expected to finish in September 2005.

Seismic offshore Libya

Compagnie Generale de Geophysique (CGG) has been awarded, in cooperation with NAGECO (North African Geophysical Company), the exclusive rights by NOC (National Oil Company) to perform a speculative multi-client seismic programme over the entire Libyan offshore. CGG will commence operations within 2Q2004 with a regional 2D seismic, gravimetric and magnetic data acquisition programme of 38,000 line-km over all licensed and open acreage.

Very little data has been acquired in the Libyan offshore in the last 20 years and much of the existing data is of a significantly older vintage. This new dataset is the first regional programme in the Libyan offshore and is the first modern dataset to extend information on the existing shelf areas and to explore the potential for prospectivity in deeper water basins, states CGG.

More Åsgard oil

A revised plan for development and operation (PDO) submitted by operator Statoil for the Åsgard Q project in the Norwegian Sea has been approved by the Norwegian authorities. The scheme involves the installation of a third (Q) template on the field's Smørbukk South deposit, tied back to the Åsgard A production ship. After experience had shown that drainage of Smørbukk South was not optimal with the existing well pattern, Statoil launched a project in 2003 to improve oil recovery from the reservoir. Åsgard Q will allow the company to get an additional 26mn barrels of oil out of the deposit.

The project will be one of the fastest subsea developments on the Norwegian Continental Shelf, says Statoil, taking just over a year to complete from PDO submission to first oil. Production from the Q template is due to start on 1 January 2005.

Extending production from Lufeng

New technology has made it profitable to extend production from Statoil's Lufeng field in the South China Sea until 2008, rather than shutting it down this past February as originally planned. It was resolved earlier this year to keep the field onstream until August, when the *Munin* production ship is due to move to another assignment. 'While the ship is away, we intend to carry out sidetrack drilling,' says Roald Riise, Vice President for Development and Production in International Exploration & Production. 'This technology, which wasn't available when we first developed the field, allows us to tap new pockets of oil which would otherwise be beyond our reach.'

Planning for the three sidetracks will start immediately, with drilling set to begin in the autumn.

Lufeng is currently producing about 6,000 b/d of oil. After the sidetracks have been drilled, this output is expected to exceed 10,000 daily barrels. More than 32mn barrels have so far been recovered from the field, well above forecasts when production began in December 1997 that total output would be about 25mn barrels.

Statoil has a 75% interest in Lufeng; CNOOC holding the remaining 25%.

In Brief

demonstrated the field installation of the world's strongest linepipe, X120'. One-mile of X120 linepipe was installed as part of a longer pipeline looping operation in Northern Alberta in February 2004. The X120 linepipe was jointly developed under an agreement between ExxonMobil, Nippon Steel Corporation (NSC) and Mitsui. 'X120 steel is 50% stronger than the strongest linepipe steel commonly used for gas transmission pipelines today (X80) and is expected to substantially reduce pipeline project costs,' comments ExxonMobil.

***Halliburton has secured a three-year** contract from ConocoPhillips to provide integrated drilling services for its North Sea activities. The contract, awarded to Sperry-Sun, includes two additional options of up to three years each.*

***Mustang Engineering was recently** selected by ChevronTexaco to perform front-end engineering design for Tahiti topsides oil and gas processing facilities. The Tahiti facility, a truss spar floating facility, will be located in approximately 4,000 ft of water in Green Canyon blocks 640, 641 and 596 in the Gulf of Mexico.*

***Murphy Oil has entered into binding** agreements under which it will sell most of its western Canadian conventional oil and gas assets for some C$829.5mn.*

***Kerr-McGee estimates that Ticonderoga,** located on Green Canyon block 768 in approximately 5,250 ft of water, offers potential resources of 30–50mn boe. Operated by Kerr-McGee with 50% interest, Ticonderoga could be developed as a subsea tieback to the company's 100%-owned Constitution truss spar facility that will be located five miles to the north.*

Middle East

***Kuwait Oil is reported to have discovered** natural gas for the first time ever in Kuwait – from the Sudair formation at 19,000 ft in the north-western field of Mutriba. The MU-12 also produced condensate measured at 50° API.*

Russia & Central Asia

***KCA Deutag, a subsidiary of Abbot** Group, has won a contract from Lukoil-VolgogradNIPImorneft for the provision of well engineering design*

In Brief

services to the Yuri Korchagin project in the central part of the northern Caspian Sea.

***Amec has won a four-year contract** from BP Exploration (Caspian Sea) for engineering and modification services in Azerbaijan. It will provide initial support services to the Chirag-1 production platform in the Caspian Sea, followed by a further five offshore installations as they become operational.*

***Sibneft has increased its equity interests** in two enterprises – Archinskoe and Shinginskoe – from 20% to 100%. The two companies hold licences for hydrocarbons deposits in the Tomsk region of western Siberia.*

Asia-Pacific

***Announcing its 2004–2005 Federal** Budget, Australia's Federal Government has unveiled plans to allow companies an increased deduction for petroleum exploration costs in designated frontier areas under the petroleum resource rent tax (PRRT) system.*

***BG Group has completed the sale of its** 50% interest in the Muturi production sharing contract (Muturi PSC) in West Papua, Indonesia to Indonesia Natural Gas Resources Muturi Incorporated (INGRMI) – a wholly owned subsidiary of LNG Japan Corporation and CNOOC Muturi – for $253mn. BG's interest in the Muturi PSC provides a 10.73% interest in the Tangguh LNG project.*

***Cairn Energy has reported that the** results from the second and third appraisal wells on the Mangala oil field in northern Rajasthan have led to an upward revision of oil-in-place reserves to between 650mn and 1,100mn barrels.*

***Genesis Power has agreed to buy New** Zealand Oil and Gas's (NZOG) share of gas from the Kupe field and fund up to $40mn of NZOG's Kupe development costs. NZOG owns 15% of the Kupe oil and gas field – which is on schedule to deliver gas in 1H2007.*

***Thailand and China are reportedly planning** to soon discuss investment opportunities in the strategic energy land bridge (SELB) project, part of Thailand's initiative to become a regional energy hub. The project involves the construction of a 2mn b/d, 250-km oil pipeline from Phangnga, which is located on the Andaman Sea in southern Thailand,*

NEWS Upstream

Decline in UKCS oil and gas output

Both UK oil and gas production was down by 11% on the year in February 2004, according to the latest Royal Bank of Scotland *Oil & Gas Index*. At 1,972,891 b/d and 12,089mn cf/d, respectively, oil and gas output was also down on January 2004.

Tony Wood, Senior Economist with The Royal Bank of Scotland, said: 'The sharp decline in oil production continues the recent trend. The impact of declining production was exacerbated by the weakening of the dollar during the past 12 months which saw UK sterling revenues fall by 20% over the year.'

Opec decided to cut production quotas by 1mn b/d from 1 April despite the sustained higher oil prices, high US gasoline prices and low stock levels. Commenting on this decision, Wood said: 'This movement reflects Opec's concern that markets could become over-supplied during the summer months. This cut is unlikely to be implemented with oil prices where they are today.'

Brent crude averaged $30.89/b in February, down slightly on the month and the year. However, recent prices were over $33/b.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Feb 2003	2,215,831	13,599	32.23
Mar	2,251,714	12,420	29.92
Apr	2,092,765	10,868	27.50
May	1,948,620	9,659	25.59
Jun	1,940,265	9,221	27.31
Jul	1,957,888	9,250	28.43
Aug	1,858,409	9,842	29.51
Sep	1,966,800	9,546	26.81
Oct	2,018,972	10,075	28.93
Nov	2,036,012	12,641	28.76
Dec	2,056,469	13,229	29.84
Jan 2004	2,014,906	13,094	31.12
Feb	1,972,891	12,089	30.89

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Cementing first

Halliburton and BP Norway recently programmed and completed what is claimed to be the first offshore cementing job using only remote control technology in an onshore operations centre some 340 km away from the project. The three-person Halliburton team accomplished the task from BP's Onshore Operations Centre in Stavanger, Norway, for BP Norge which operates the water injection platform in the Valhall field in the southern part of the Norwegian North Sea.

'This is really breaking a new barrier for us in terms of taking remote control of offshore operations to a new dimension,' explained John Gibson, President and Chief Executive Officer of Halliburton's Energy Services Group. 'We now are moving quickly toward our vision of being able to control and monitor most operations and processes from the beach,' added Audun Bjordal, Halliburton's Fluids Division Country Manager in Scandinavia.

Centrica expansion

Centrica's North American business unit Direct Energy is to acquire Canadian natural gas producer Quintana Minerals Canada Investments Corporation for C$51.5mn in cash. Quintana has a natural gas portfolio in north-central and east-central Alberta, with proven reserves of 16.2bn cf and proven plus probable reserves of 19.4bn cf. Quintana's current net production will increase Direct Energy's existing production by 11%.

Centrica Chief Executive Sir Roy Gardner said: 'Our strategic purchase of Quintana will give us greater supply control and flexibility to meet our North American customer demand, currently maintaining our ability to supply around 20% of our retail gas needs from our own production.' The deal follows Centrica's earlier announcement that it is soon to complete the acquisition of the retail gas and electricity business of the ATCO Group in Alberta, adding approximately 1mn customers.

ATEX-approved offshore rental module

Aberdeen-based offshore accommodation provider Duffy and McGovern recently brought what it claims is the world's first ATEX-approved offshore rental module to market. The module, which cost in the region of £100,000 to develop, has successfully met the criteria for the new European Union ATEX (atmosphere explosible) Directive 94/9/EC. The unit will now be supplied to the Wood Group for the BP Lomond platform. Seven standard A60 sleeper units are also being supplied along with the ATEX module, which will be used as a locker room in a category three (Zone II) area of the rig.

Latest news from European Union

The European Bank for Reconstruction and Development (EBRD) is bankrolling the development of Kazakhstan's oil and gas reserves, a key alternative supply for the European Union (EU), reports *Keith Nuthall*. It wants to lend Tasbulat €60mn to help develop three medium-sized oil and gas fields in Mangistau region, western Kazakhstan, producing up to 8,000 b/d in 2006. Tasbulat is owned by SNP Petrom, Romania's national oil company. Meanwhile, the EBRD wants to lend Chinese-Kazakh joint venture MunaiTas €70mn to cover 35% of costs for building a Kenkiyak–Atyrau oil pipeline connecting the Aktobe region of central Kazakhstan with Atyrau to the west. From there existing pipelines can carry crude oil to the Black Sea.

In other EU news:

- Dominant gas companies and network authorities should be bound by the same proposed obligations to free up pipeline capacity for foreign competitors offering cross-border supplies, say European Parliament amendments to a new gas transmission regulation. MEPs were concerned that monopolistic gas suppliers could use control of capacity slots in a pipeline network nominally run by a transmission regulator to circumvent the regulation.
- The European Commission (EC) has closed a gas network access case involving the Norwegian subsidiary of American gas producer Marathon, after negotiations stretching from the 1990s. The deal involves French and German gas companies Gaz de France (GdF) and Ruhrgas improving third-party access to their networks. GdF will, for instance, halve the number of tariff zones restricting movement across France. Ruhrgas will simplify booking procedures at gas network entry and exit points.
- Eastern and southern European countries who joined the EU in May have been granted requested stays of execution over the implementation of common EU minimum levels on energy taxation. Agreed exemptions last up until 2012 and cover gas (for the Czech Republic, Hungary, Malta, Latvia, Poland, Lithuania and Slovenia), for instance.
- The European Commission is threatening France, Belgium, Netherlands, Germany, Austria, Italy, Portugal and Sweden with legal action at the European Court of Justice (ECJ) for failing to comply with an EU law promoting low sulphur petrol and diesel.
- The EBRD and the World Bank will help fund building a distillate oil combined cycle power station in Vlore, Albania. The EBRD will supply €40mn of the €91–110mn cost; the World Bank will fund $25mn.
- The European Parliament has surrendered in its row with the EU Council of Ministers over whether MEPs can veto pared-back legislation to help guarantee gas supplies during emergencies. Ministers have now passed the law alone.
- The European Investment Bank (EIB) is planning to lend the Egyptian Electricity Holding Company €150mn to build new 750-MWe natural gas-fired combined-cycle power plants at Talkha, in the Nile Delta, and at El-Kuriemat, south of Cairo.

In Brief

with Sichon, located off the Gulf of Thailand; construction of oil loading and offloading facilities at either end of the pipeline; construction of storage terminals and berthing facilities. China, Japan and Oman are understood to have expressed an interest in participating in the project, which, once completed, will provide oil traders a shorter alternative to the congested Straits of Malacca.

Latin America

***ExxonMobil, Ecopetrol and Petrobras** have signed a participation agreement to begin exploration activities over the Tayrona block, offshore Colombia's northern coast. Petrobras will be the operator during the exploration phase, with ExxonMobil taking over during the development phase in the event that gas is discovered on the block.*

***Total (69.5%) reports that Phase 1** of the Yucal Placer gas project in Venezuela has come onstream and will produce some 100mn cf/d of gas at peak. Phase 2 development will boost production to 300mn cf/d from 2007.*

Africa

***ChevronTexaco recently reported** that the Angola block 0 concession held by its wholly-owned subsidiary Cabinda Gulf Oil Company (CABGOC) has been extended beyond 2010 to 2030 by the Government of Angola and national oil company Sonangol. The concession comprises 36 major fields, including Takula and Malongo. Current average production from the block is approximately 400,000 b/d of oil.*

***BP (50%) is understood to have made** a gas discovery in the Ras El Barr concession in the Nile Delta region, some 12 km to the north-east of the Ha'py gas field. The Taurt discovery well tested at 22mn cf/d, constrained by the capacity of the test equipment.*

***The Gulf of Guinea Joint Development** Zone (JDZ) – which is managed by Nigeria and Sao Tome and Principe – is to be developed by a number of oil majors, including ChevronTexaco, who has been appointed the operator (51%) of oil block 01, and ExxonMobil who has a 40% stake in the block. Norway's Equity Energy Resources (EER) holds 9%.*

In Brief

UK

***Shell has reported a 1Q2004 net** income of $4.4bn, while BP posted a net income of $4,717mn.*

***Lloyd's Register has published a set** of guidelines for the new concept of offshore gravity based liquefied gas terminals.*

Europe

***OMV Erdgas and Gazexport have** expanded and extended their gas supply contracts until 2012.*

***The owners of HubCo and Eurohub,** which both operate gas marketplaces in Germany's Emden-Bunde region, have agreed to continue operations through a joint company.*

North America

***ConocoPhillips has announced the** formation of a Global Gas organisation, as a new division of its Exploration & Production (E&P) operation.*

***GE Energy, a division of General Electric** Company, is to acquire ChevronTexaco's gasification technology business for an undisclosed sum.*

***US Federal Reserve Chairman Alan** Greenspan is reported to have recently stated that the current high oil and gas prices are most likely here to stay and are putting the US economy through an energy shock akin to – but smaller than – the one that transformed American life during the 1970s.*

***ExxonMobil has reported a 1Q2004 net** income of $5.4bn, down $1.6bn from 1Q2003 which included a $550mn positive impact from the required adoption of the new accounting standard for asset retirement obligations and a one-time gain of $1.7bn from the transfer of shares in Ruhrgas. Excluding these impacts, 1Q2004 earnings were a record and increased by $650mn. ChevronTexaco has reported what is claims is a record net income of $2.6bn for the 1Q2004, compared with net income of $1.9bn in the previous year period. Meanwhile ConocoPhillips posted a 1Q2004 net income of $1.6bn ($1.26bn in 1Q2003); Petro-Canada $517mn ($485mn); Apache Corporation $348mn ($338mn); Marathon Oil $258mn ($307mn);*

Supporting LNG projects

Intec Engineering of Houston has launched an LNG business unit to support operators in the offshore development of LNG systems. The new business will assist customers in the early evaluation of LNG development options while also extending a total project engineering solution capability.

Competitive gas prices and global demand for gas as a clean-burning fuel find industry looking to significantly boost LNG trade from a current 125mn t/y to about 200mn t/y by the end of the decade, comments Intec. At present, LNG makes up about 2% of US gas consumption, with an anticipated increase possibly as high as 20% by 2020.

Investments in new LNG facilities through 2007 are estimated to exceed $30bn, with majors and independents aggressively proposing multiple new-build offshore terminals and associated equipment for delivery over the next decade. The cost of these terminals has the potential of exceeding $1bn, making the decision-making process extremely critical, says Jerry Wenzel, Intec's Vice President of LNG Engineering Services and Business Unit Manager.

In the US alone, industry has proposed some 40-plus newbuild LNG import terminals, both onshore and offshore. Government agencies and industry forecasters, however, expect that only four will be built by the close of the decade – two anticipated offshore the Gulf Coast, one offshore the East Coast, and another offshore the West Coast. Two or three more LNG terminals may proceed in the following decade.

The industry is initially focusing on four major types of LNG offshore terminals, says Wenzel – floating units, gravity-based units, conventional fixed platforms and tanker-based re-gasification units. New technologies, and other emerging configurations of these systems, also are being developed and tested with the goal of creating additional offshore solutions. These technologies involve cryogenic hoses and subsea pipelines, new subsea re-gasification systems, offshore LNG storage and gas storage in subsea salt caverns.

Shell report on reserves recategorisation

Shell has released the executive summary and proposed remedial measures sections from the report to the Group Audit Committee (GAC) into the facts and circumstances surrounding the recategorisation of the Group's hydrocarbon reserves. In addition, Shell released the outcome of its reserves recategorisation review prepared with the assistance of the Ryder Scott Company, an outside consulting firm. This follows the interim conclusions announced on 18 March 2004. Shell also announced changes to its reserves practices to address the issues raised by these reports and establish a sound base for future reserves reporting by Group companies.

The summary states:

- **Shell's Boards fully accept the findings of the GAC report and will ensure prompt action on its recommendations.**
- **90% of Shell's proved oil and gas reserves have been reviewed, with external assistance. The final result of all the recent reviews is that a total of 4.35bn boe will be recategorised as at end-2002. Additionally, 2003 reserves will fall by 0.5bn boe.**
- **External experts will be involved in the annual audit and reporting of reserves.**
- **Shell has decided to restate financial statements in the 2002 Form 20-F, which is to be amended. The impact on earnings averages around $100mn/y, less than 1% of earnings in the period 2000–2003.**
- **Judith Boynton has stepped aside from her position as Group Chief Financial Officer, but will remain an employee of the Group. Tim Morrison has been appointed as acting Group Chief Financial Officer with immediate effect.**
- **The review of corporate governance announced on 18 March 2004 is to be accelerated.**
- **The non-executive directors unanimously give their complete support to the current executives of the Committee of Managing Directors (CMD).**

Jeroen van der Veer, Chairman of the CMD, said: 'The report to the GAC and the reserves recategorisation review draw a line under the uncertainties that have surrounded the status of our reserves since 9 January. The controls we now have in place will be rigorously enforced and will be subject to far greater levels of scrutiny within Shell. Despite the difficulties of recent months Shell is a sound and profitable business. We are making the changes to our reserves practices to ensure that that remains the case.'

Deals signed for China LNG terminal

Guangdong Dapeng LNG Company* has signed a series of agreements that underpin the commercial and operational success of China's first LNG terminal and trunkline project, which is due onstream in 2006. BP, with a 30% interest, is the sole foreign participant in the project which, when completed, will supply imported gas from the North West Shelf project offshore Australia – where BP is also a partner – to Chinese customers in the Pearl River Delta area, Guangdong Province and Hong Kong.

The agreements include:

- Gas sales contracts, each for a 25-year term, with ten Chinese power generation and city gas companies. This will involve the supply of a total of 3.2mn t/y of natural gas produced by re-gasifying imported LNG.
- A non-recourse project financing agreement, worth some $665mn, for the terminal and trunk line with Industrial and Commercial Bank of China, Agricultural Bank of China and China Construction Bank, China Development Bank, and Bank of China. The Guangdong LNG terminal and trunkline project is located near Dapeng village, east of Shenzhen, in Guangdong Province. It will have an initial capacity of 3.7mn t/y and 370 km of trunklines stretching from Shenzhen through to Dongguan, Guangzhou, Foshan and Zhujiang to supply natural gas to city gas and power plants in Guangdong and Hong Kong.
- An engineering, procurement and construction (EPC) contract executed with STTS – a French-Italian consortium. This contract provides for the construction of the LNG reception facilities that will receive, store and re-gasify LNG from the North West Shelf Joint Venture.
- LNG vessel time charter party arrangements with Yuepeng LNG Shipping Company and Yuegang LNG Shipping Company, respectively for the chartering of up to three LNG vessels for the transportation of LNG to the Guangdong LNG terminal. It is envisaged that the LNG vessels will be built by Hudong Zhonghua Shipbuilding in Shanghai.

*The shareholders of Guangdong Dapeng LNG Company are: CNOOC Gas & Power (33%); Guangdong Investments and Pearl River Delta Investments (30%); Shenzhen Gas (10%); Guangdong Yudean Group (6%); Guangzhou Gas (6%); Shenzhen Energy (4%); Dongguan Fuel Industrial General Company (2.5%); Foshan Municipal Gas General Company (2.5%); Hongkong Electric (Natural Gas) (3%); and Hong Kong & China Gas Investment (3%).

Troubling times for Yukos

Yukos is understood to have received notice from its lending banks of a 'potential event of default' on the company's $1bn loan. According to Standard & Poor's (S&P), this restricts Yukos' ability to raise funding and to withdraw cash from exporter accounts that are used to secure syndicated bank debt (and do not require immediate repayment of debt).

In S&P's opinion, this 'increases the chances of creditors announcing a full "event of default", which would 'trigger cross-defaults whereby all the company's financial debt becomes immediately due and payable'. Such cross-defaults would include the $1.6bn export-linked financing arrangement with Menatep Group as guarantor. This would, in turn, 'put further stress on Yukos' liquidity, which is already being pressured by a $3.5bn potential tax claim – the court hearing for which is expected in May – and by the freeze of its parent company's assets. These assets include shares in all the company's key operating subsidiaries and in Siberian Oil Company.'

S&P continues: 'Under the stress scenario, if Yukos loses the tax case or if an "event of default" is announced by the company or its creditors, Yukos might experience a liquidity crisis, forced sale of core assets, insolvency procedures, or effective nationalisation of its assets.'

According to analyst UFG: 'While Yukos has the necessary cash to repay the $1bn syndicated loan, the cross-default provisions would ensure that its immediate obligations exceeded its ability to repay them. Total debts are some $3bn against cash of $1.2bn, and while we estimate that Yukos generates $2.7bn/y in free cashflow, the company's operations would be constrained by the likely need to use all its export earnings to repay its hard currency loans. This would mean that the company would need to operate on its domestic earnings alone, leading to large reductions in its capex and operating expenditure.'

In Brief

Imperial Oil $509mn ($538mn); Unocal $269mn ($134mn); Talisman Energy $223mn ($574mn) and Anadarko Petroleum $392mn.

***The Boards of Kerr-McGee and** Westport Resources have unanimously approved a strategic merger valued at approximately $3.4bn. The merged company will be known as Kerr-McGee Corporation and will be headquartered in Oklahoma City.*

***A new report from Energy Security** Analysis is understood to have indicated that a large increase in LNG gas imports by 2005 and the payoff of investments in domestic E&P activity in North America could force US gas prices as low as $4.25/mn Btu in 2007.*

Middle East

***Apache Corporation has signed a gas** sales agreement (GSA) with the Egyptian General Petroleum Corporation (EGPC) covering 2.1tn cf of natural gas from the Qasr field on Apache's Khalda Concession in Egypt's Western Desert. Principal terms include the supply of 300mn cf/d of gas to the Egyptian market, rising to 650mn cf/d during 2005.*

Russia & Central Asia

***Viktor Gerashchenko, the former** Chairman of the Central Bank of Russia (CBR) and a top executive with Halliburton has been nominated to take the post of Yukos Chairman.*

Asia-Pacific

***Shell has signed a $1bn IT outsourcing** deal with IBM and Wipro Technologies of India. The master services agreement will see parts of Shell's IT projects and services outsourced offshore during the next few years as part of the company's plan to save $850mn/y from its IT budget.*

Africa

***Tullow Oil is understood to have sealed** a $500mn (€414mn) takeover of Energy Africa, paving the way for the creation of one of the largest oil firms operating in West African region. The company has also agreed to acquire from African Petroleum Investment its 50% stake in EAGHL, a joint venture with Energy Africa, for a further $70mn.*

In Brief

UK

The UK Freight Transport Association, *in association with Albion Chemicals, has published a new ADR Driver's handbook, which provides essential guidance on the new ADR aligned British dangerous goods regulations that entered into force on 10 May 2004.*

Amec has won a £50mn contract from *Star Energy HG Gas Storage to develop and manage construction of a gas storage plant and pipeline at Humbly Grove, Hampshire, UK. The project is due for completion in October 2005.*

The IPE (International Petroleum *Exchange) recently reported that April 2004 closed as the best ever April for both the Brent Crude and Gas Oil futures contracts, with 2,070,175 lots and 723,968 lots traded respectively. Collectively, these volumes represent 2.6bn barrels of crude oil and an underlying value of over $92bn.*

The UK Government is planning to *redeem the special shares it holds in five energy companies – National Grid Transco, Viridian Group, Phoenix Natural Gas, Scottish Power, and Scottish and Southern Energy. It has also confirmed that it plans to retain its special shares in British Energy.*

Scottish and Southern Energy (SSE) is *reported to have completed the purchase of the assets of Atlantic Electric & Gas for £90.7mn from the latter's receivers, KPMG.*

Tesco has become the first major *retailer to bring biodiesel to customers around the UK, announcing the start of a national roll-out of Greenergy GlobalDiesel on 29 April 2004. Over the next year, estimated sales of Greenergy GlobalDiesel at Tesco will deliver a reduction in carbon dioxide emissions of over 2,000 tonnes – equivalent to the amount created by 7mn driver miles.*

BP has announced plans to consoli- *date the Olefins and Derivatives (O&D) Division of its petrochemicals business into a stand-alone entity able to operate separately from the BP Group.*

Simon Plant, of specialist insolvency *firm SF Plant + Co, has been appointed liquidator of Emir 8 Petroleum, the UK-based wholesale provider of fuel oil, storage and distribution.*

Range of alternative fuel initiatives unveiled in US

BP is to collaborate with DaimlerChrysler in field-testing fuel cell vehicles in the US beginning this year. The vehicle test programme is part of a five-year 'Controlled Hydrogen Fleet and Infrastructure Demonstration and Validation Project', funded in part by US Department of Energy (DoE). The project is designed to gain real-world experience with fuel cell vehicles (FCVs), to address related issues such as fuels and fuelling infrastructure, and to educate the public about this developing technology. DaimlerChrysler has proposed to supply its FCVs to fleets in certain US markets. BP proposes to provide the refuelling infrastructure to support the fuelling needs of those fleets.

In addition, Ford Motor Company and BP have announced a major initiative aimed at moving the US closer to a hydrogen economy. Ford intends to place up to 30 hydrogen-powered Ford Focus FCVs, and BP plans to build a network of fuelling stations to support them, in metropolitan Sacramento, Orlando, and Detroit. Some of the BP hydrogen refuelling stations will evaluate technologies that have near-term commercial feasibility, such as reformation of natural gas, while others will explore more long-term technology options and assess the potential to produce renewable-based hydrogen that achieve US DoE hydrogen fuel cost targets. The Ford Focus FCV uses an 85-kW fuel cell stack supplied by Ballard Power Systems, the world leader in proton exchange membrane (PEM) technology. The FCV is hybridised with the addition of a nickel metal–hydride battery pack and a brake-by-wire electro-hydraulic series regenerative braking system.

Under the proposal, Ford intends to station up to 10 Focus FCV vehicles in each of the three metro areas of Orlando, Sacramento, and Detroit.

Alameda-Contra Costa Transit District and ChevronTexaco have also announced an innovative cooperative agreement to build a state-of-the-art hydrogen energy station in Oakland, California, that will produce hydrogen fuel for fuel cell fleets. The hydrogen will fuel AC Transit's fleet of 40-ft Van Hool/UTC/ISE fuel cell buses and future fleets of light duty vehicles (cars, SUVs, and small trucks) in support of Governor Arnold Schwarzenegger's vision of a hydrogen highway network in California. The station will have the additional capability of utilising excess hydrogen production to generate high quality electrical power from a stationary fuel cell.

The station, which will be capable of dispensing as much as 150 kg of hydrogen per day, is under development and is scheduled to be completed by August 2005. Unique to the station's design is the use of small scale, onsite steam reforming of natural gas, to produce hydrogen in the most cost-efficient manner for commercial applications. This approach is consistent with the findings cited in the recent National Academy of Engineering report on the hydrogen economy, states ChevronTexaco.

Meanwhile, a project team led by Air Products, including automobile manufacturers Toyota Motor Sales USA, American Honda Motor, Nissan North America, BMW, ConocoPhillips, the National Fuel Cell Research Center at the University of California at Irvine, the University of California at Davis, and the California South Coast Air Quality Management District automakers are to work together to further demonstrate and validate advancements in hydrogen-based transportation infrastructure.

Over the five-year programme, up to 24 fuelling station locations using multiple approaches to producing hydrogen and providing fuelling infrastructure could be developed. These include a fuelling station located on a pipeline, relocatable stations placed at existing retail gasoline stations including ConocoPhillips sites, as well as municipal locations. These fuelling stations will be supported by hydrogen produced from both natural gas and renewable energy sources. Some of these stations will also have dual dispensing capability of gaseous and liquid hydrogen.

Toyota, Honda and Nissan plan to assign, collectively, up to 65 FCVs to this project, and BMW plans to assign up to 15 hydrogen-fuelled internal combustion engine vehicles. The vehicles are to be driven by a broad range of drivers and interested parties including technical experts, policy makers, vehicle customers and fleet operators. The project team requested DoE funding of approximately $35mn of the overall award for hydrogen infrastructure activities and a public outreach programme.

Competitiveness of fuel retail networks

Over the next few months *Petroleum Review* will be looking at various branded retail networks across Europe using a technique developed by Catalist that objectively measures a network's retail competitiveness from the perspective of two critical factors.

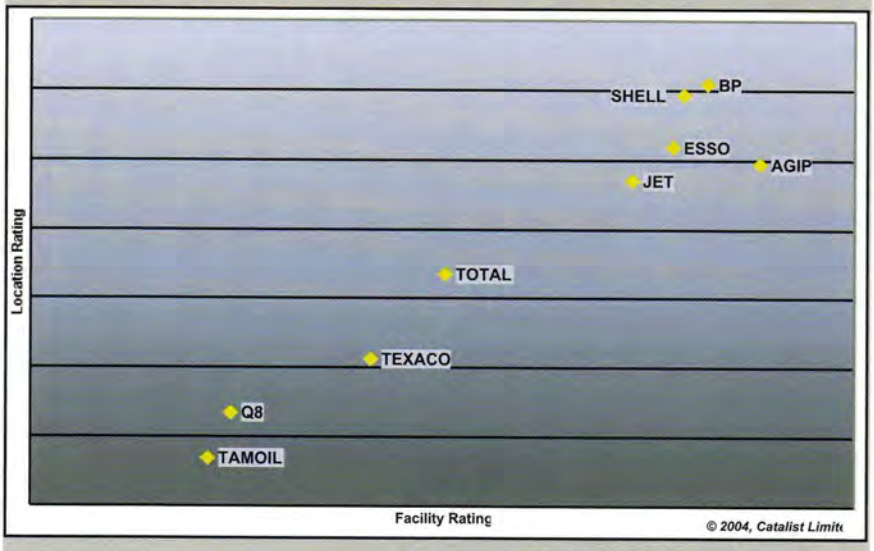
The first of these factors is the 'Location Rating'. This is a measure of the overall quality of the location attributes of a petrol station from a fuel retailing point of view. These factors include traffic flow, accessibility, visibility, plot size, demand demographics and other key location-based factors.

The second is a measure of a site's ability to attract customers by way of the type and quality of its facilities. In this instance, factors such as number of fuelling positions, shop type, size, product categories and other features of each petrol station are measured.

The accompanying chart shows the average location and facility ratings of some of the major brands found across Europe. Of course, each market has its own characteristics. For example, what constitutes a strong location in Italy may have a different impact in Germany. For this reason the scores are adjusted to take this into account and give international comparability.

In this month's example we have analysed the major brands that operate in at least four different countries. It is not surprising to see the main brands such as BP, Shell and Esso in the leading spots in terms of location and facility strengths. However, it appears that Agip has leadership in terms of facility strengths. Look in future issues of *Petroleum Review* for more detailed insights into various European countries.

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



Source: Catalist Ltd, 2004. All rights reserved.

First commercial cellulose ethanol fuel

Shell Global Solutions International has confirmed that Iogen Corporation, a world-leading biofuels technology company, is successfully producing the world's first cellulose ethanol fuel available for commercial use.

In some countries – for example Sweden, the US and Brazil – conventional ethanol is already blended into gasoline.

Cellulose ethanol has two primary advantages over conventional ethanol. Firstly, the greenhouse gas emission reductions from cellulose ethanol are three times greater than those from grain-based ethanol on a life-cycle basis. Secondly, cellulose ethanol is made from a plentiful and renewable resource, the non-food portion of agriculture crops (eg straw, corn stalks and corn cobs).

By contrast, conventional ethanol is made from the food portion of agricultural crops (eg sugar, corn, wheat and barley), feedstocks that have important alternative demands.

In Brief

Europe

Fortum is to acquire the City of Oslo's *53.7% stake in pan-Nordic power and heat company Hafslund for €660mn.*

The International Finance Corporation *(IFC) of the World Bank will lend $65mn to Turkish fuel importer and retailer Opet Petrolcülük, helping it build a marine terminal and tank storage facility, while buying another small terminal. This would help expand Opet's retail distribution network, writes* Keith Nuthall.

The Norwegian Government has proposed *a new ownership strategy for state-owned Statkraft that could see the government reducing its stake in the company if a suitable strategic partner were found.*

Eastern Europe

Polish petrochemical company PKN *Orlen is understood to have submitted the sole bid for the state's 63% stake in the Czech petrochemical giant Unipetrol, offering CZK13.05bn.*

North America

Plains All American Pipeline has *acquired the Cal Ven pipeline system from Cal Ven, a subsidiary of Unocal Canada, for $19mn.*

Centrica has reached agreement to *complete the C$90mn acquisition of the retail gas and electricity business of ATCO Group in Alberta, Canada.*

Russia & Central Asia

Surgutneftegaz, Russia's fourth-largest *oil producer, will invest $1.7bn to build a new port on the Baltic Sea and upgrade its only refinery by 2008 so that it can export higher-grade fuels in an effort to expand its market share, reports* Mark Rowe. *Surgut is working with ABB on a $1.1bn upgrade at its 38-year-old KINEF refinery, south of St Petersburg. Surgut also plans to invest $600mn to build a port at Batareinaya Bay.*

Asia-Pacific

BP's two Chinese retail service station *ventures have taken a step forward*

In Brief

with the signing of joint venture contracts and articles of association for both the BP Sinopec Zhejiang Petroleum Company and the BP PetroChina Petroleum Company. These joint ventures will each acquire, build and operate 500 retail service stations in the Zhejiang and Guangdong Provinces respectively by 2007.

***Sinopec and Shell have signed a 60:40** joint venture contract to develop a network of some 500 service stations in Jiangsu Province, China, over the next three years at a cost of some $200mn.*

***Shell is reported to have applied for a** licence to sell petrol and diesel in India after it completed the pre-requisite investment of Rs20bn in oil infrastructure in the country. The company has invested more than RS20bn on a new 2.5mn tonnes LNG import and regassification terminal at Hazira in Gujarat.*

***TXU has sold its portfolio of Australian** electricity and gas assets to state-owned Singapore Power for $3.72bn including cash and debt assumption.*

Tank deliveries from Heil Trailer

Bilston-based Heil Trailer International recently delivered 72 new articulated fuel tankers to Shell contractors Hoyer UK (52 units) and JW Suckling Transport (17 trailers), to be used on deliveries throughout the UK. All manufactured to ADR specifications, the equipment includes a mixture of tri-axle petroleum tankers with up to 42,800-litre capacity, tandem axle tanks with 28,000-litre capacity and 31,000-litre capacity, as well as black oil and aviation fuel tanks.

UK Deliveries into Consumption (tonnes)

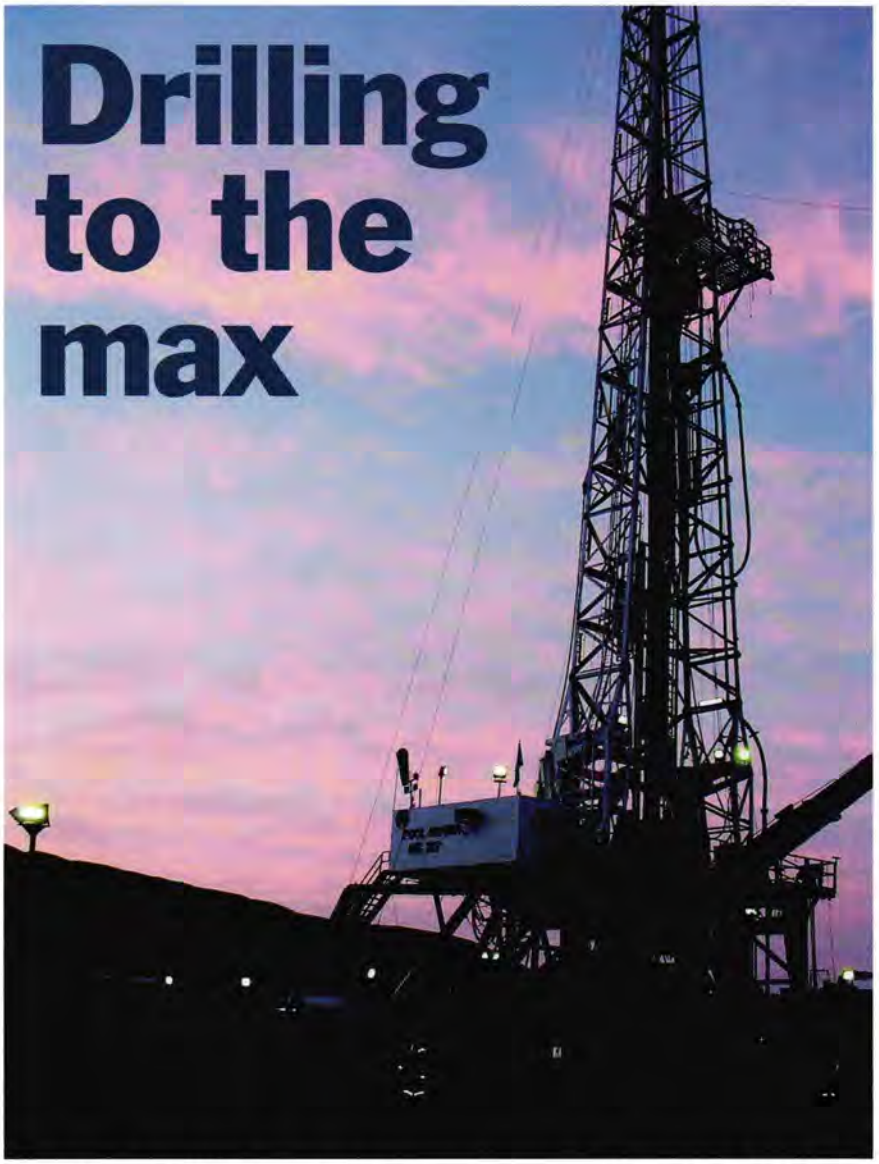
Products	†Feb 2003	†Feb 2004	†Jan–Feb 2003	†Jan–Feb 2004	% Change
Naphtha/LDF	239,848	200,437	439,839	430,691	–2
ATF – Kerosene	708,294	747,378	1,553,384	1,600,349	3
Petrol	–	–	–	–	–
of which unleaded	1,508,186	1,501,505	3,001,648	3,047,218	2
of which Super unleaded	64,538	60,746	137,178	121,219	–12
ULSP (ultra low sulfur petrol)	1,443,648	1,440,759	2,864,470	2,925,999	2
Lead Replacement Petrol (LRP)	18,246	7,290	37,974	15,072	–60
Burning Oil	513,377	482,006	1,013,763	1,008,795	0
Automotive Diesel	1,337,185	1,491,651	2,733,217	2,973,945	9
Gas/Diesel Oil	531,491	512,605	1,068,427	1,035,140	–3
Fuel Oil	168,330	190,709	415,728	439,944	6
Lubricating Oil	68,635	60,681	138,089	114,957	–17
Other Products	600,972	796,156	1,352,044	1,561,362	15
Total above	5,694,564	5,990,418	11,754,113	12,227,473	4
Refinery Consumption	387,553	331,800	889,425	808,873	–9
Total all products	6,082,117	6,322,218	12,643,538	12,559,273	–1

Products	†Mar 2003	†Mar 2004	†Jan–Mar 2003	†Jan–Mar 2004	% Change
Naphtha/LDF	256,938	162,350	696,777	593,041	–15
ATF – Kerosene	54,117	789,276	2,307,501	2,389,625	4
Petrol	–	–	–	–	–
of which unleaded	1,640,794	1,691,078	4,642,442	4,738,296	2
of which Super unleaded	63,095	73,423	200,273	194,642	–3
ULSP (ultra low sulfur petrol)	1,577,699	1,617,655	4,442,169	4,543,654	2
Lead Replacement Petrol (LRP)	20,778	7,359	58,752	22,431	–62
Burning Oil	358,607	521,907	1,372,370	1,531,773	12
Automotive Diesel	1,423,812	1674,136	4,157,029	4,646,667	12
Gas/Diesel Oil	59,624	595,676	1,608,051	1,630,816	1
Fuel Oil	201,696	178,521	617,424	618,465	0
Lubricating Oil	67,545	70,877	205,634	185,834	–10
Other Products	706,754	960,566	2,058,798	2,520,857	22
Total above	5970,635	6,651,746	17,724,748	18,877,805	7
Refinery Consumption	371,402	471,728	1,260,827	1,352,499	7
Total all products	6,342,037	7,123,474	18,985,575	19,753,231	4

† Revised with adjustments

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

Drilling to the max



Modern drilling technology is now allowing field operators to create production wells with immense exposure to pay zones, writes *Gordon Cope*. But will maximum reservoir contact (MRC) wells turn out to be a boon, or a curse?

Photos: WellDynamics

In the last several years, an exciting new drilling technology has been hailed as a way to rejuvenate production in everything from offshore fields in the North Sea, heavy oil in Venezuela and mega giant projects in the Middle East.

Maximum reservoir contact (MRC) wells – also known as horizontal, multilateral wells (see also p16) – are essentially horizontal production wells with several lateral offshoots. While a conventional, single horizontal well might be in contact with the reservoir for a total of 2,000 ft, an MRC well typically has a total reservoir contact greater than 10,000 ft.

The goal of an MRC well is to increase production of a field, yet do it at a lesser overall cost. A single horizontal well, for instance, might have to penetrate 3,000 ft of non-productive overburden before it is then drilled horizontally through 2,000 ft of pay. An MRC well, on the other hand, only penetrates the overburden once before splitting off several times in the pay zone. 'If you can get 2,000 ft of contact in five wells and 10,000 ft of contact in [an MRC well], then you only have to drill one well,' says Guy Arrington, Manager of Drilling & Measurements for Schlumberger Canada.

The arithmetic might be simple, but the execution requires a complex series of steps. Each well is custom-designed to take into account the properties of the reservoir, hole stability, potential formation damage, interference with offset wells and comparative economics with alternative production methods (such as fraccing). The drilling itself requires advanced equipment owned and operated by only a handful of service companies around the world. If done correctly, production (when compared to a single, horizontal well), can increase by 200–600%. When done incorrectly, however, it can lead to sanding in, watering and permanent loss of portions of the reserves.

Knowing when to drill MRC wells and when to eschew them is the province of experts like Dr Kenny Adegbesan. The Calgary-based reservoir engineer is a horizontal well specialist with KADE Technologies. In addition to teaching horizontal well engineering at the University of Calgary, he has consulted with oil companies around the world. In his opinion, several factors make reservoirs good candidates for horizontal, multilateral wells. 'A thin reservoir is a positive factor, because you have tremendous economic leverage [when comparing horizontal wells to vertical]. With the quality of geo-steering, you could manage down to 3 metres [of reservoir thickness] without hitting the reservoir cap or aquifer.' Carbonate reservoirs have

their advantages, because if the reservoir is damaged during drilling, one can do an acid frac to repair permeability.

On the other hand, there are many types of reservoir in which MRC wells are not recommended. 'If a reservoir is very stratified (alternating shale and sand, for instance), then vertical permeability is low and there is little advantage to a horizontal well,' explains Adegbesan. Oddly, thicker reservoirs are also less attractive. 'A thick pay zone means good contact in a vertical well, so a horizontal well is not as economically advantageous.' Lithological stability of the reservoir is also very important. 'With a vertical well, you normally cement and perf, but it's too expensive for a long horizontal well. Sandstone [under openhole conditions] can break off and sand in a well.'

However, most geological provinces have good candidates for MRC wells, however. Saudi Arabia, in addition to having the world's largest reserves of conventional oil, also has many attributes amenable to horizontal, multilateral wells. 'They have good permeability compared to North American fields,' comments Adegbesan. 'Many fields are well consolidated, which creates good stability, and they have a relatively low stratification problem.'

Intelligent completion specialist WellDynamics recently installed the first SmartWell® completion in Saudi Arabia – in a trilateral maximum reservoir contact (MRC) well in the Shaybah field for Saudi Aramco. The SmartWell technology provides inflow control from each lateral branch, resulting in more efficient clean-up, stimulation and production control for the life of the well. The Shaybah 119 completion is a three-lateral SmartWell completion, employing hydraulically actuated interval control valves with Accupulse™ to allow selective variable choking of each of the laterals, without costly intervention.

Dr Nansen G Saleri, Manager of Reservoir Management at Saudi Aramco, said: 'Advanced well completion is one of our technology focus areas and we firmly believe that SmartWell technology will contribute to our goals of improved reservoir management with maximum recovery while reducing well count.'

Shaybah field

Saudi Aramco first began to explore the value of MRC wells at Shaybah, a 14bn barrel field located in eastern Saudi Arabia. The field, discovered in 1968, contains 42° API oil in low permeability carbonates and has a large overlying gas cap and underlying aquifer. In order to mitigate gas encroachment and to achieve high production rates in a low permeability formation, single horizontal wells were drilled in the mid-1990s and the field put into production. After a comprehensive study of the field and its production, a decision was made to drill an MRC well in 2001.

In a paper presented to the Society of Petroleum Engineers in 2003*, Nansen Saleri, Manager of Saudi Aramco's Reservoir Management Department; Salam Salamy, a Senior Petroleum Engineer; and Saud Otaibi, General Supervisor of the Gas Reservoir Management Division, outlined the process. Starting in 2002, a main wellbore (also known as a motherbore), was drilled to the target formation, where special 'geo-steering' equipment was employed to continue penetration into the reservoir.

While horizontal drilling with a downhole motor has become relatively common in the oil industry, there are only a handful of service companies worldwide, including Baker Hughes, Sperry-Sun and Schlumberger, that possess the suite of tools and software to drill MRC wells. 'Motors are old technologies, and still the most common,' says Arrington. 'Rotary steerable systems (RSS) are the next generation.'

RSS tools are similar to standard drilling systems in that the drill bit is rotated by the drillstring, which gives a smoother, cleaner wellbore with less torque and drag. It differs from a conventional system in the manner in which the drillbit is aimed, however. Schlumberger's system, for instance, uses three exterior pads sitting directly behind the drillbit to deviate the direction of drilling by applying directed pressure against the rock. It does so using an internal valve that controls the flow of mud to pad actuators. As the bit rotates through each revolution, the pads are extended and retracted in sequence to provide consistent pressure against one side of the wellbore. The bit can thus be deflected in a smooth, continuous arc.

Obviously, for the MRC well to be productive, it must remain within the confines of the pay zone. Too high, and the wellbore is exposed to the gas cap, which can cause slugging in the production stream. Too low, and it runs afoul of the underlying aquifer. Too wayward, and it penetrates into unproductive lateral rock. Keeping it just right means knowing not only *where* it is at all times, but *what* it is in, as well.

The *where* is controlled by a location unit positioned as close as possible to the drill bit. The most advanced units, generically known as measurement while drilling (MWD), contain direction and deviation sensors mounted on bearings within the drill collar. This allows the sensors to remain stationary so that they can take tilt and azimuth measurements while the drillstring is rotating.

The *what* is supplied by logging while drilling (LWD) devices. The LWD suite includes most of the conventional wireline logs, including resistivity, density-neutron and sonic devices. They can be used to provide comprehensive geological and petrophysical evaluation, allowing the operator to identify approaching formation contacts by distinguishing lithological changes in four directions (up, down, left and right). Thus, a drill bit that is approaching a shale layer overlying the carbonate reservoir is able to distinguish the fact, and the driller can alter course. It can also be used to steer the drill bit toward higher porosity.

Such information, of course, is of dubious merit after the fact. The bottom hole assembly (BHA) is thus

invariably equipped with either mud pulse telemetry or e-pulse (low-frequency electromagnetic waves that pulse through the rock) communication systems. As the drill bit advances, the systems allow MWD and LWD information to be transmitted uphole in real time, as well as new commands to be transmitted downhole to the tool.

At Shaybah, MWD and LWD information was sent by satellite communication from the rig site to offices in Dharan, Saudi Arabia. The live link allowed real-time, 24/7 well geo-navigation. No major problems were encountered during drilling or post-drilling, and by the end of 2003, nine MRC wells were completed and placed onstream. Initial studies show that all the wells experienced significant gains in productivity and reductions in unit development costs.

In their paper, Saleri *et al* noted that, at Shaybah, a conventional horizontal well with 3,280 ft completion produces 2,000 b/d of oil. An MRC well with 25,584 ft pay zone exposure produced 12,000 b/d. The initial cost of drilling the conventional horizontal well amounted to $1 per b/d output. The comparable cost of the MRC well amounted to 38 cents. Saudi Aramco's successful experience has since been applied to the Abqaiq and Ghawar fields.

A quibble with Yibal

As previously reported in *Petroleum Review***, however, MRC wells have their detractors. Matt Simmons, President of Houston-based, private investment banker Simmons and Co, took issue, in part, with modern technologies during an evaluation of Middle East reserves and production life. In a February 2004 review presented to the Center for Strategic and International Studies in Washington, DC, Simmons expressed a pessimistic interpretation regarding the prospects of Ghawar, Saudi Arabia's (and the world's) largest oil field.

As part of his thesis, he pointed to Saudi Aramco's increased use of MRC wells, declaring that, although the wells can maintain and even increase production, they rarely augment total yield, and in fact may hasten decline. As an example of what can go wrong, Simmons pointed to the Yibal field in Oman. First drilled in 1962, Yibal was produced using a standard system of water injection and pressure maintenance through vertical wells. The field began to experience problems after 1990, however, when horizontal wells were introduced. Production at first rose, peaking at approximately 250,000 b/d in 1997, then began to decline at a rate of 12% per year. By 2003, Oman officials noted, the field was producing in the range of 90,000 b/d. About 90% of the liquid coming out of the ground at Yibal is water, and the remaining 10% oil. (It was speculated that the high volume of water comes in part from the water injected into the ground as part of its horizontal drilling technique. Regardless, the water adds considerably to the costs of extracting the oil). 'Instead of creating easy supply growth, the technology revolution created monstrous decline rates,' said Simmons.

Saudi Aramco officials were quick to refute the charges, asserting that their estimates of reserves and petroleum engineering practices were sound. In a recent interview with the *Oil & Gas Journal*, company officials noted that Shaybah's current production of 560,000 b/d (with a water cut of approximately 10%) was achieved with 70 wells less than the original estimate of 170 wells, thanks largely to MRC technology. Furthermore, the output could be expanded to 1mn b/d with little risk of negative impact to the reservoir.

But the question of Oman's Yibal field lingers – What reservoirs make bad candidates for MRC? Part of the problem, says Adegbesan, could be related to the amount of energy coming from the oil or aquifer. 'If you drill into a new field and the initial oil pressure is high, is it due to the oil, or the aquifer? If initial assumptions overstate oil energy, the field can water out earlier than expected.' Another problem could relate to production history. Yibal was produced with vertical wells for decades before horizontal wells were introduced. Generally, layers of high permeability deplete first, leaving residue oil in areas of lower permeability. Later, if a decision is made to drill horizontal wells into the areas of lower permeability to recover the residue oil, water that has displaced oil in the depleted high permeability zones may enter the new wells.

The future

So far, the number of horizontal, multilateral well completions has been relatively low, but, where proper preparation has been done, MRC drilling has proven itself to be cost-efficient and safe. Drilling experts expect usage to expand in the coming decade, first in areas where production drilling costs are relatively high. 'In the North Sea, for instance, you can drill from one platform and save costs,' says Adegbesan.

Regions that are already adopting MRC will also become more comfortable with the technology. 'Early on, there were a number of mistakes made,' says Adegbesan. 'In the Middle East, as we get more and more experience, we will know better how to manage them.'

Finally, economics will play a huge roll in their expanded use. Adegbesan notes that completion of multilateral wells can range from a simple open hole to sophisticated production modules that allow each lateral to be independently produced. 'The higher up you go, the more expensive it gets, but in the future, we will have advances in drilling and production that will make it cheaper, and you'll have more multilateral wells. We will also see advances in geological sciences and seismic as they relate to reservoirs.'

**'The expanding role of the drill bit in shaping the subsurface', Nansen Saleri, Salam Salamy, Saud Otaibi, SPE 84923.*
*** 'A tale of two planets', Julian Darley,* Petroleum Review, *April 2004.*

Multilateral well planning and execution in deep waters

Multilateral technology has gradually gained acceptance as a reservoir development tool in recent years. *Karl DeMong*, Middle East Multilateral Operations Manager, Sperry-Sun, Halliburton Energy Services, looks at the development of this technology and its application in deepwater projects.

The rapid advencement of multilateral system improvements has increased well integrity, productivity and accessibility. Casing junctions that could be selectively re-entered have been developed, making possible re-entry with full drift assemblies for workover. These completions initiated true multilateral features, including full flow control in commingled applications as well as lateral exit though tubing for the rigless well intervention.

The latest generation of multilaterals provides accessibility, flow control options, segregated through-tubing access to each lateral, pressure isolated junctions and capabilities to enable full workover applications. The completion can be upgraded at any time. This evolution allows each lateral to have all of the features of an independently drilled well, which has always been the goal of multilateral well designers. Multilateral designs can be adapted to most reservoir management and production applications.

For its installation, the multilateral junction or completion uses an oriented profile sub or latch coupling, either in the casing in a new well or installed in a packer in an existing well. When the latch coupling is installed, it is oriented with survey equipment such as a gyroscopic survey tool or inclinometer in survey-while-drilling tools. Once the latch coupling is set on depth and oriented, all other junction creation or entry functions run to depth and orient with mechanical checks.

Differentiators for deepwater operations

Deepwater multilateral operations force a different planning and execution approach from land and platform projects. Developments on land or platform-based multilateral operations have focused on cost of equipment, access to the legs and the ability to intervene in the well using a rig to shut off water, plug back and redrill laterals, or add artificial lift. The opportunity cost of a land drilling location may be several orders of magnitude less expensive than a deepwater drilling slot. An undrillable lateral or a lost slot may make a small impact on a land operation, while junking a deepwater lateral or main well may reduce reserves.

The operational steps required in the well completion are selected and sequenced for minimum risk and maximum chance of success. Rather than looking at the multilateral well as the addition of a new part to the well, like a dual packer, a system approach analyses each operational step to assess the risk, then takes measures to fulfill the requirement while reducing the risk.

An example is the desire to get a picture of the production coming from each lateral in a multilateral well. Mechanical intervention or electronic systems may be used. Both have a finite risk that might be unacceptable for deepwater. In one deepwater application, an operator decided to use several radioactive isotopes in the lateral screens. The production was monitored to create a synthetic production profile, reducing the mechanical and operational risk of the operation at the expense of defining the well data. This can be typical of the difference in risk management in the deepwater environment.

The type and timing of the stimulation and sand control operations are also an issue in deepwater. Stimulations cannot be easily mobilised to the well after rig release. Even while the rig is on the well, 'optional stimulations' based on production tests are not common.

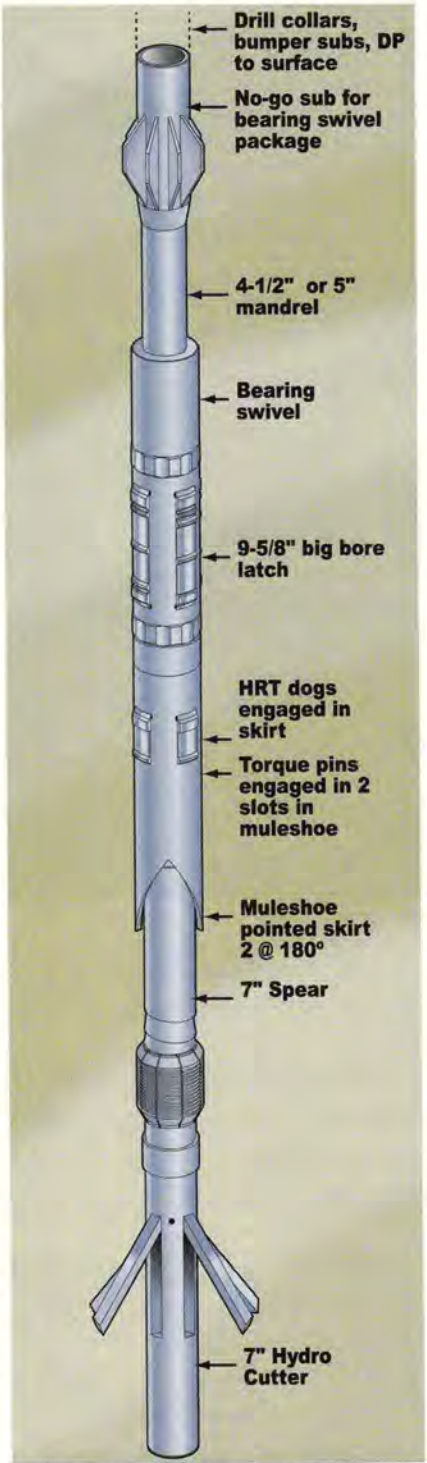


Figure 1: Cut on depth tool. The 'on depth' group of tools was developed to operate at an exact depth without uncertainty regarding depth or weight on the bottomhole assembly

Each lateral may only be accessible for a few days or weeks while the well is being constructed. Re-accessing the well usually requires setting a deflection device at minimum, but may require the mobilisation of a rig. Additional trips and risk are not usually acceptable. If there is moderate chance that a stimulation will be required, it is planned and executed during the initial well construction.

Sand control has also received attention. Washing over a failed gravel pack in a multilateral well in deepwater is undesirable, so there has been more of an emphasis on using premium and expandable screens.

Critical issues

Costs for non-productive time become a key point in deepwater multilateral projects. The time and trips required for multilateral operations also becomes critical.

The costliness of deepwater also means that the prospects tend to have higher reserves and production rates than land wells, which has led to larger inner diameter (ID) systems.

The cost to return to a deepwater well is also prohibitive, so through tubing access completions are run less often. Systems that provide for flow control but not for access have been developed precisely for this purpose. Interventionless completion equipments, where the flow is controlled from surface, such as disappearing plugs and hydraulic single trip packers have been used. Intelligent well completions are also a consideration where flow control is desired.

Overall there has been a reluctance to run in deepwater the same types of multilateral junctions that are run on land. Deepwater has demanded multilateral systems with fewer trips to install, less operational risk, and larger IDs. Access has not been required, but interventionless water shut-off or other remedial features are desired.

Several completion options have been developed for deepwater wells. The PerfRite™ System, the FlexRite™ System and the intelligent well completions, which can be run in the MillRite™ junction, were developed with deepwater constraints in mind.

Constructing the multilateral junction in the deepwater well differs from constructing the junction from a fixed surface. Most drilling compensators require a moderate weight to function. Many multilateral junction construction operations such as running tools, fishing, or washing over are done with very little weight. They also require a greater degree of control than that afforded by a drilling compensator.

The 'On Depth' group of tools was developed to operate at an exact depth without uncertainty regarding depth or weight on the bottomhole assembly. These tools drop liners at a designated depth, accurately set packers, mill from or to a specified depth, set liner hangers, wash over multilateral equipment and precisely cut off liner tops. The tool uses a latch coupling set in the main casing. When locked into position, the precise depth is known.

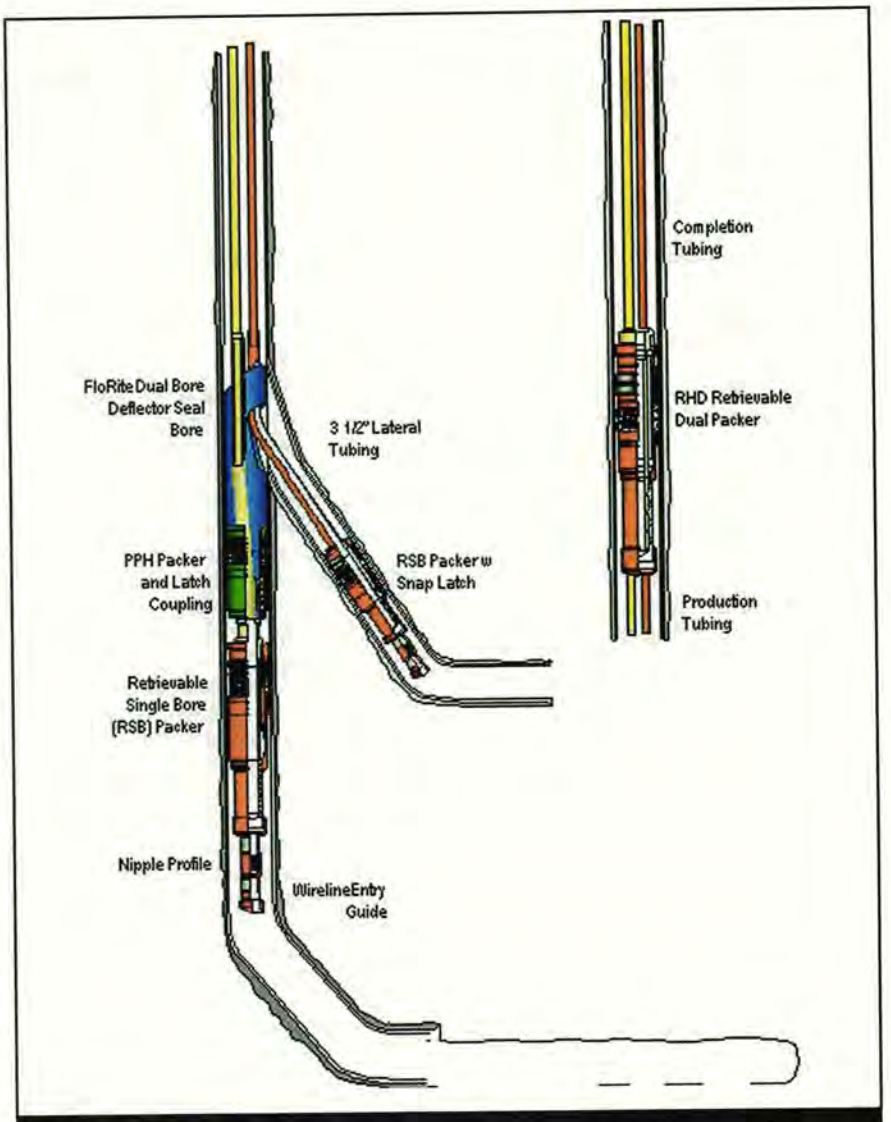


Figure 2: MillRite™ junction w/FloRite™ completion in existing well – TAML Level 5 permanent through tubing access both bores

Maintaining hole size through or below a junction is important. Each new casing string reduces hole size 25–30%. Using a multilateral junction compounds hole size reduction. Savings anticipated from using multilateral wells are often consumed by the cost of a corresponding increase in hole size to the depth of the junction. In some cases, a 50% reduction in hole size occurs through the junction.

Applying multilateral technology to existing wells exacerbates the problem. The multilateral well re-entry is constrained to the previous casing size. The retention of hole diameter in these applications becomes paramount. In deepwater applications, where the cost of the well is high to start, the value of hole size retention is critical. Size reduction is greatly reduced through using expandable tubulars.

New well case study

The FlexRite™ system can be run to the surface as a single or dual completion. The top end of this system is similar to the FloRite™ system (also a TAML Level 5 completion system) already employed in many multilateral wells. This system provides selective re-entry and intervention capabilities in the lateral and main bore. It is also possible to stack the systems to provide more than one lateral capability from a single well bore if selective re-entry of the lower well bores is not required.

continued on p34...

Pipe dream snuffed out

Energy in Latin America is moving from the control of the market to the control of politicians. *Maria Kielmas* reports.

As Argentina prepares for winter in the midst of increasing gas and electricity supply cuts, local comedians have revived a joke that circulated in Brazil during that country's energy crisis in 2001–2002. As the former Brazilian President, Fernando Henrique Cardoso, struggled to introduce an energy rationing plan, the question on the streets was: 'What is the difference between the Cardoso Government and the Titanic?' The answer was: 'The Titanic went down with its lights on.' Brazilians may have laughed, but the Cardoso Government then introduced a successful energy rationing plan and turned the crisis around. A crisis, it should be noted, caused by drought and high gas prices, not political mismanagement.

But now no-one in the Argentine Government is laughing at the joke today as Argentina's energy crisis becomes international. 'Never, since the return of democracy in both countries, have relations between Argentina and Chile been so dramatically tense,' wrote Joaquín Morales Solá, who is one of Argentina's most respected political commentators.

In Chile, the feeling is one of isolation and anger. Since 1988, when Chile regained its democracy, the country has been held up to its neighbours as a paragon of economic rectitude. But the results of similar economic reforms in Argentina, Bolivia and Brazil have ranged between the unsatisfactory and the disastrous. Now populist leaders in these countries are seeking solutions through an old utopianism based on reinforcing the role of the state in the energy sector – and excluding the Chilean market from their plans. As a result Chile, a country surrounded by significant oil and gas producers and whose gas consumption is less than that of the Irish Republic, is considering offers of LNG imports from Indonesia and the adoption of the latest cost-effective second-generation nuclear energy technology.

Who is to blame?

The search for scapegoats has begun on all sides of the Andes. Industry and political opinion is divided into two camps – either foreign investors have not fulfilled their work obligations and have not paid sufficient taxes, or that government policies and regulatory changes have made such investments unviable. However, the true reasons for this regional energy crisis may be uncomfortable for both sides.

The initial problem was that the 1990s energy privatisations that took place in Argentina were conducted back to front. First came the disposal of the electricity sector, which was sold off with no one having a clue as to what kind of fuel market the privatised utilities were to operate in since the oil and gas sectors were still state-owned. The internal oil market was liberalised in theory but, as it has always been dominated by a handful of companies, it has never shed popular accusations that it acts as a cartel. When the state gas monopoly Gas del Estado (GdE) was privatised in late 1992, the government had little idea about the kind of future gas market it expected.

Local industrial groups grabbed available exploration acreage, recycling a lot of it to foreign investors in return for fat commissions. But even this just replaced a state-sector oil monopoly with a private sector oligopoly. The new operators carried out wholesale workovers in fields but little exploration. This was similar to the privatised gas utilities who spent most of their time repairing the old transportation infrastructure, or by installing meters, rather than building new pipelines. Many foreign gas companies did not include clauses in their concessions with the government detailing the separate definitions of work obligations in terms of time and in terms of money. As a result, the investors and the regulators have been fighting about the issue ever since.

Although there were major gas discoveries in the Noroeste Basin near Bolivia and in the Austral Basin in the South Atlantic offshore, government officials in Argentina's neighbouring countries of Brazil and Uruguay had already estimated that Argentina would become an oil and gas importer in the medium term. This is a point of view shared today by Daniel Fernández, the President of Chilean state oil company Empresa Nacional del Petróleo (ENAP). But this had been forgotten amid the euphoria of opening new gas export pipelines to Chile and Brazil.

However, probably the biggest failure of the privatisation exercise was that it did not introduce an entrepreneurial culture into the country, to replace the traditional mercantilist one. Local industry has never been in the business of taking risks and was always unlikely to provide a serious impetus for exploration. But this realisation became muted as the proponents and opponents of energy sector privatisation divided into ever more doctrinaire camps.

Low gas prices

Since the Argentine Government's declaration of an economic emergency in January 2002, the freezing of utility tariffs, and the removal of the peg between the peso and the dollar, the government and utility investors have made little progress in renegotiating their contracts. The companies blame the energy crisis on the government's policies since 2002, while a recent report by gas regulator Enargas blamed the gas producers and distribution companies.

The report claimed that these companies had financed 83% of their capital investment through external loans, which could be written off against tax. The companies had under-invested, under-explored and over-produced, with all new projects directed towards the export, rather than the internal, market. And now, like the oil market, 85% of the gas market is controlled by four companies – Repsol-YPF, Pan American Energy, Total and Petrobrás.

In early April 2004, the government and gas producers reached an agreement for a 40% increase in wholesale gas prices, from 45 US cents/mn Btu to 63 US cents, on condition that the producers ensured supplies to the residential market. Yet industrial gas users in Argentina can expect to suffer gas shortages of between 60 and 70 days, with a shortfall of 8mn cm/d expected by mid-winter. To counter this the government has ordered a cut in gas exports to Chile – first by 30% and then by 45% – while arranging a six-month gas supply contract with Bolivia for 4mn cm/d. In addition, it has halted electricity exports to Uruguay, which account for 19% of Uruguay's power demand, and contracted emergency electricity imports from Brazil.

LNG project stalls

A long-gestating project by European investors in Bolivia to export LNG from a Pacific port floundered last October amid bloody riots and the toppling of the then President Gonzalo Sánchez de Lozada. The investors hoped to export the gas from a Chilean port, their most economic option. But this notion triggered both recidivist and nationalist protests in Bolivia, leaving the government with no option but to condition a Chilean export terminal for the project on the return of coastal territory that Bolivia lost as a result of the 19th-century Pacific war with Chile. A protest bandwagon involving cocoa farmers, indigenous groups and trade unions gathered pace, forcing the government of Carlos Mesa to introduce new petroleum legislation.

Subject to a referendum scheduled for 18 July 2004, this law will increase royalties on oil and gas production from 18% to 50%, probably making a gas export project unviable and leading to the resurrection of the former state oil company Yacimientos Fiscales Petroliferos Bolivianos (YPFB). The new YPFB will have control of all aspects of the oil and gas industry and will hold majority shares in future joint ventures with foreign investors. As soon as the legislation is approved, companies with existing upstream contracts will have 180 days to switch to joint development, joint production, operational or association contracts with the new state company.

Argentina originally hoped to import 9mn cm/d of Bolivian gas. Since the 2002 devaluation, Argentina has enjoyed strong, though unsustainable, economic growth coupled with surging gas demand, due to high world oil prices, high soya exports to the Chinese market and low energy costs at home. However, Bolivian protest groups and the government have been suspicious that this gas would be re-exported to Chile.

In probable contravention of World Trade Organisation (WTO) rules (of which both countries are members) the Bolivian supply contract states that no re-exports to Chile will be permitted. Bolivian President Carlos Mesa assured his electorate that 'not a molecule' of Bolivian gas will go to Chile, prompting Chilean conservative opposition leader Joaquín Lavín to reply that 'not a drop' of the Pacific Ocean will be ceded to Bolivia.

In late April, Indonesia offered to sell LNG to Chile. Indonesia has also snapped up the US and Mexican LNG markets which Bolivia was hoping to acquire.

Diplomatic failure

The opposition in Chile is exploiting the failure of the Ricardo Lagos Government to solve the gas supply crisis, which could stunt Chilean economic growth. The crisis has already prompted rating agencies to downgrade Chilean power utilities, which account for nearly 40% of the Santiago stock market's capitalisation and are a significant element in the country's private pension funds. The failure of Foreign Minister Soledad Alvear to reach a diplomatic understanding with her Argentine opposite number, Rafael Bielsa, has probably destroyed her chances in next year's Presidential elections in Chile.

Chilean gas buyers are hoping to seek compensation for their losses through international tribunals, in particular to test a non-discrimination provision clause in the 1995 bilateral gas supply protocol with Argentina. Argentine President Néstor Kirchner dismissed this saying that, as the Argentine Congress had never ratified the 1995 protocol in the first place, it is not valid under Argentine law and there is no international claim possible. Chilean gas buyers, Kirchner said, should try to obtain compensation from gas exporting companies in Argentina. The gas exporters, for their part, are claiming *force majeure*, since the Buenos Aires Government has obliged them cut firm, rather than interruptible, supply contracts with Chilean buyers.

By early May, the Chilean Government was trying to ease the tension, stating that it would not pursue any claims in the international courts – yet.

Chilean political commentators claim that Argentina has never honoured any international agreement, and Chile cannot link its economic future to such a neighbour. Chilean energy links with Bolivia were written off after last October's riots in La Paz. Energy experts in Bolivia also worry about how their own relationship with Argentina will develop. The present gas export deal is worth $45mn/y. However, the experts ask: 'Will Argentina pay, and who in Argentina will pay?' The government in Buenos Aires is planning to create a new state-owned energy company which will control and regulate the energy market, but there is no clarity about its role in the international gas trade. In addition, Bolivian officials worry that Brazil will increase pressure on La Paz to cut Bolivian gas exports prices to Brazil. These are nearly 60% higher than the price Argentina will pay.

The present Brazilian Government under President Luiz Inácio Lula da Silva, and its predecessor, tried and failed to negotiate a cut in Bolivian gas exports prices. This led to a fall in Brazilian gas offtake through the Bolivia–Brazil gas pipeline to less than 8mn cm/d. However, offtake had risen to 28.5mn cm/d by late April, as Brazilian gas demand rose. This coincided with an announcement in Argentina that it would cut gas exports to southern Brazil because of the supply crunch. So far, Brazilian reaction has been calm. But government energy officials have made clear to Buenos Aires that present electricity exports to Argentina may be halted should a drought trigger future power supply problems in Brazil.

More integration

Brazil, Bolivia and Argentina are maintaining a diplomatic façade over their international energy trade complications. Relations between Buenos Aires and Brasilia chilled briefly with the revelations in March that Brazil had developed a uranium enrichment facility without the knowledge of Argentina. Brazil at the time had denied access to inspectors from the Vienna-based International Atomic Energy Agency (IAEA), leading to a frosty exchange with Washington. In late April, Brazilian Energy Minister Dilma Rousseff proposed that Brazil, Bolivia and Argentina move forward with the integration of their state-controlled energy sectors, notably excluding Chile from the proposal. In Chile this was viewed as yet more international pressure to address Bolivian claims to Pacific coastal territory.

But Brazilian energy policy is entering an uncertain period as the government's centre-right coalition partner, Partido del Movimento Democrático Brasileiro (PDMB), demands and receives jobs for its own placement at the head of the main federally-controlled energy companies, Petrobrás and Elétrobrás. The first victim has been Luiz Pinguelli Rosa, the Elétrobrás President, an academic nuclear physicist, a fierce critic of the 1990s energy privatisations in Brazil and the architect of the present government's energy policy that has tried to stall the expansion of the gas market. This policy was made redundant by the discovery last year of 14.5tn cf of gas in the offshore Campos and Santos Basins.

Back in Argentina, President Kirchner shows few signs of listening to the proponents of orthodox energy polices. This approach is supported by his staunch allies – Government Minister Aníbal Fernández and Planning Minister Juan De Vido, while Economy Minister Roberto Lavagna supports a more conciliatory strategy with foreign investors. That said, Kirchner's popularity is growing as he succeeds in deflecting the country's economic problems with an international crisis and blaming it all in foreign investors.

There is an urgent need now not only to confront reality, but to find the willingness to do so, noted Joaquín Morales Solá. Otherwise, he said, it could be too late.

A key player in the global gas arena

The fact that western hemisphere Energy Ministers chose to assemble in Tobago in mid-April for their sixth Ministerial Conference which focused on designing an 'energy security policy' for the region, was a clear indication of Trinidad and Tobago's current eminence in the global natural gas industry, writes *David Renwick*.

The small south Caribbean island nation last year supplied 77% of all US imports of LNG. Although LNG was only 2–3% of US natural gas demand, as domestic gas sources decline and Canadian gas becomes less available it is likely to rise to 25% of US gas usage by 2025 – and Trinidad and Tobago fully intends to remain the major provider.

The Caribbean country is also the world's largest exporter from a single site of two gas-based chemical products – methanol (4.66mn tonnes after the new Atlas plant came onstream this year) and ammonia (5.1mn tonnes when the latest such facility, Nitro 2000, commences production shortly).

Trinidad and Tobago's gas reserves – 20.76tn cf proven and 8.28tn cf probable – are relatively modest when compared with other countries in the hemisphere, but its success lies in the speed with which they have been monetised. At least $7bn has been poured into gas-related projects, including three LNG trains, six methanol plants (with a seventh to come in 2005) and 10 ammonia plants. Current gas production for domestic use and export as LNG amounts to 2.7bn cf/d from 12 fields.

Commitment to gas

Arnold De Four, Manager for Gas Resources Management at the state-owned National Gas Company (NGC) – which operates the gas transmission system and has been mandated by the government to promote gas-based development – confidently expects the monetisation momentum to continue unabated. 'Ammonia and methanol production is going to be dead in North America very soon,' he predicts. 'All these plants will be coming to Trinidad.' Little wonder then that US Energy Secretary, Spencer Abraham, who attended the Tobago conference at which the US was co-sponsor with Trinidad and Tobago's Energy Ministry, praised the 'Trinidad model' of natural gas development as 'a very effective example of how a country with natural gas resources can enter the international marketplace... our hats are off to the leadership in Trinidad and Tobago.'

The Caribbean state's Energy Minister, Eric Anthony Williams, a geophysicist by profession, says: 'That model is built around a commitment by the government to develop natural gas resources in particular areas – ammonia, methanol, LNG and metals, including aluminium. The country has established itself as a world-class player in all those areas, except aluminium, and we hope to enter that business very soon.'

This 'commitment to gas development' was probably music to Secretary Abraham's ears, since 'energy security' – the main issue dealt with at the conference – is of paramount importance to Washington bearing in mind the instability in the Middle East and gas supply shortfalls in North America. The US energy chief would also have been pleased to hear that, having only recently signed off on the $1.1bn, 800mn cf/d, 5.2mn tonne Atlantic train 4, the Trinidad and Tobago Government has indicated that it is prepared to go ahead with trains 5 and 6. With a swap arrangement with Spain in operation, almost all of Trinidad's 1.5bn cf/d of LNG now goes to the US and the US territory of Puerto Rico. It is almost certain that the vast majority of train 4's output will also end up there as well.

The same is likely to apply to the proposed trains 5 and 6, which will see new gas reserve holders, such as BHP Billiton/Total/Talisman, being brought into the LNG picture in Trinidad for the first time.

So far, the major gas reserve holders such as BPTT, BG International and Repsol-YPF, as principal owners of the Atlantic LNG Company in Point Fortin, south-west Trinidad, have grabbed most of the LNG opportunities. However, the government wants to spread the benefits of North American LNG pricing among more players – not only because companies need to be encouraged to explore for gas as much as possible, but also for the tax benefits that accrue to the state from LNG netback pricing flowing through to the wellhead.

Venezuelan gas in the mix

As far as a train 6 is concerned, the government has hinted broadly that this may have a large component of Venezuelan gas in its mix from the unitisation projects now being pursued across the maritime border between blocks on the Trinidad side and those in the Plataforma Deltana development north-east of the Orinoco Delta. Negotiations on how to proceed are currently taking place and by year's end it should become clearer how the estimated 7tn cf of gas that straddles the border in three areas can best be exploited. Since Venezuela has little, or no, infrastructure in Plataforma Deltana, the decision is likely to be to do it from the Trinidad side, at least as far as the Kapok reserves in Trinidad held by BP and the Dorado discovery by PdVSA in block 1 in Venezuelan waters, are concerned.

The US is probably encouraged by the fact that Trinidad is receptive to the idea of monetising Venezuelan gas on the Trinidad side of the border, at least until Venezuela gets its own LNG facility, which has still not yet been given the green light.

The current state of relations between the Venezuelan President Hugo Chavez Frias and Washington, suggests that the US is more likely to feel 'energy secure' if Trinidad is the LNG supplying source. However, it is not only the US that is concerned about energy security, but also the Caribbean Community and Common Market (Caricom) countries whose Ministers attended the Tobago conference. Their concern primarily centres on the fluctuating prices of refined oil products and the extraordinary strain this imposes on their balance of payments. For example, Jamaica, the largest Caricom market, spent $700mn last year on importing petroleum products – 58% of all its foreign exchange earnings.

President Chavez came up with a scheme in 2000 to supply crude oil or products to Caricom states at a subsidised price, but this has never been fully implemented. Trinidad has now proposed to Venezuela that it uses the state-owned Petrotrin refinery in Trinidad to produce the products covered by Chavez's programme, bearing in mind Petrotrin's long history of involvement in the regional oil trade. Energy Minister Williams points out that 'some eastern Venezuela oil fields are much closer to Trinidad than they are to Venezuela's own refineries and bringing that oil to Trinidad for refining and re-export makes sense.'

In the pipeline

In a sense, such a measure would be only a stop-gap until Caricom begins to move towards what Trinidad and Tobago perceives to be the region's real investment in energy security – a natural gas pipeline. While Jamaica, like the US, Puerto Rico and, most recently, the Dominican Republic, prefers LNG as the vehicle by which it can gradually replace fuel oil with natural gas in power generation, Trinidad is proposing piped gas instead for the smaller Caribbean markets such as Grenada, St Vincent, St Lucia, Barbados, Martinique, Dominica and Guadeloupe.

Initial studies have examined the idea of a 596-mile long line between Trinidad and the French department of Guadeloupe to the north, expected to cost between $510mn–$550mn. About 100mn cf/d of gas would be required initially to produce about 646 MW of power likely to be needed by the seven territories.

The project is a private sector initiative but has been enthusiastically received by the Trinidad and Tobago Government, which sees in it a chance to extend to the wider Caribbean some of the same benefits that Trinidad itself has derived from being a gas-powered economy. While LNG to Caribbean markets have not been able to escape the price fluctuations inherent in a link with Henry Hub in the US, pipeline gas would be much more stable, priced on a cost plus basis, with negligible variable costs.

Venezuela has also expressed an interest in being involved in pipeline gas to the Caribbean. Energy Minister Williams told *Petroleum Review* that: 'Both Venezuela and ourselves feel we can assist in intra-regional development and make the region more attractive to investors by lowering the cost of electricity to the Caribbean in a way that is commercially viable.'

LNG expansion, the Caribbean gas pipeline, Secretary Abraham's own proposal for a Western Hemisphere Energy Technology Co-operation Initiative and other proposals from the Tobago conference will all go forward to the Summit of the Americas meeting in Argentina next year to become key ingredients in an 'action plan' for the 34 nations that make up the forthcoming Free Trade Area of the Americas (FTAA).

Oil still important

While Trinidad and Tobago's hemispheric energy role now clearly centres around natural gas, oil still remains a key element in the country's hydrocarbon mix, providing self-sufficiency in transportation fuels, substantial foreign exchange earnings and sizeable public revenue (although taxation derived from gas-based activities recently began to exceed that from oil).

Proven:	990 (highest for 40 years)
Probable:	324
Possible:	1,853
Total:	**3,167**

Source: Ministry of Energy and Energy Industries.

Table 1: Trinidad and Tobago oil reserves, in mn barrels, January 2003

Proven:	20.76
Probable:	8.28
Possible:	6.06
Total:	**35.10**
(highest ever; equivalent to 6.05bn barrels of oil)	
Identified exploratory resources:	30.7
Unidentified exploratory resources:	28.0
Grand total:	**93.8**

Source: Ryder Scott and Ministry of Energy and Energy Industries.

Table 2: Trinidad and Tobago non-associated natural gas reserves, in tn cf, January 2003

Oil, the commercial production of which in Trinidad goes back to 1908, has been on a downward slide since peak production of 229,589 b/d in 1978. Energy Ministry forecasts for 2004 suggest liquids output of 132,868 b/d, but 15,742 b/d (or 11.8%) will be condensate, which comes courtesy of the gas. So, 'real' oil production will be down to only 117,126 b/d, 51% of the 1978 level.

The good news is that oil has been given the 'kiss of life' in Trinidad, thanks to BHP Billiton's Angostura discovery, whose main feature was a mid-case estimate of 160mn barrels of 29°–32° API gravity crude. First production is due in December this year at about 58,000 b/d, from three wellhead protector platforms – Kairi One, Kairi Two and Canteen One. This will immediately restore Trinidad and Tobago's liquids output to around 190,800 b/d once existing production holds steady, a level last seen in 1981. Angostura oil will quickly ramp up to about 80,000 b/d, boosting overall country production to about 212,800 b/d – last attained in 1980 and only 17,000 b/d short of the all-time record.

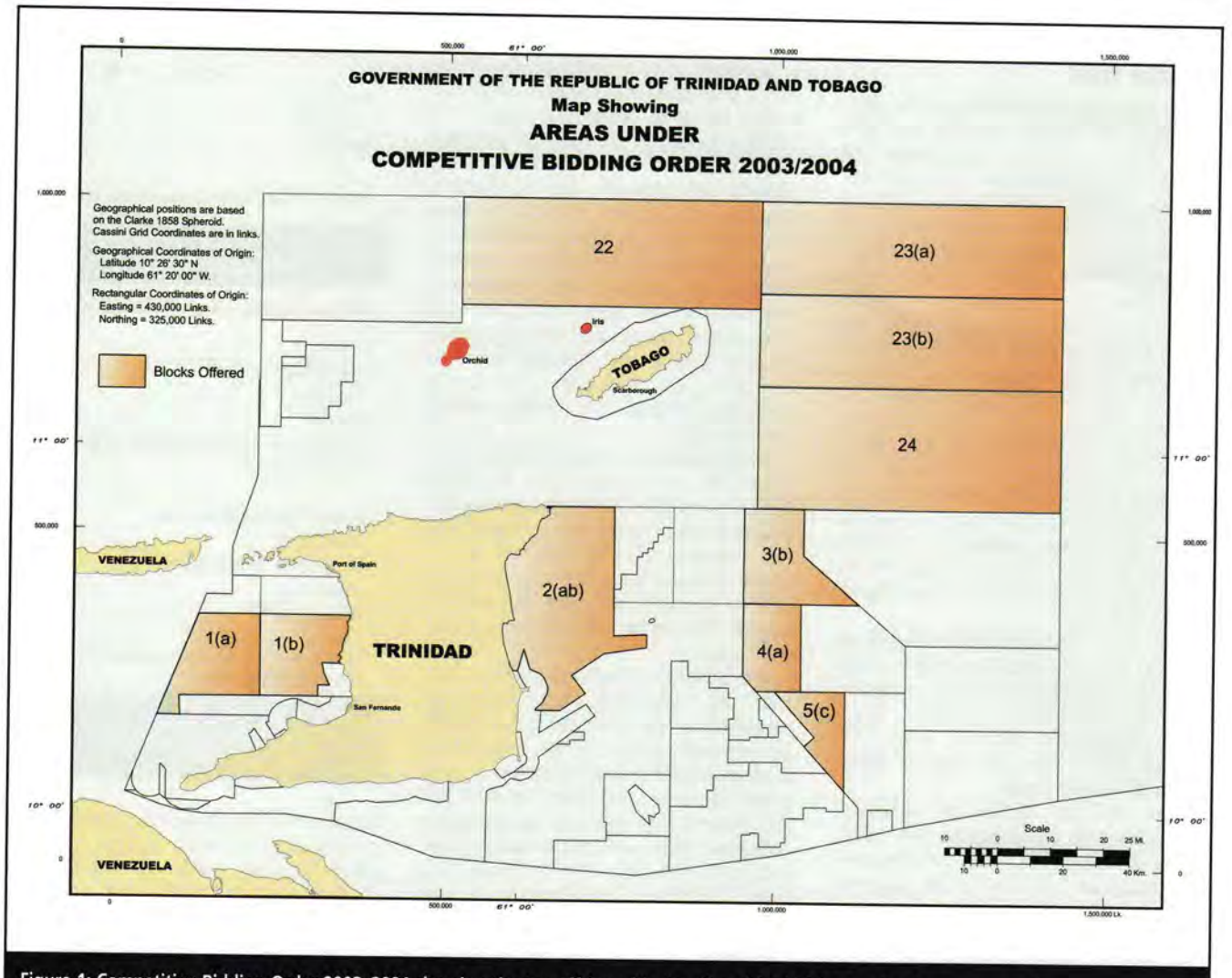


Figure 1: Competitive Bidding Order 2003–2004 showing the ten offshore blocks offered for bidding by the Government of Trinidad and Tobago.

BHP Billiton is confident that more is to come and has already quietly announced an oil strike in block 3a, adjacent to 2c, where it is also the operator, partnering Talisman, BG International and Total. Oil was found with Puncheon One, the third of three exploratory wells drilled there. The company says it needs to undertake 'further analysis of the well' before it can determine how the discovery compares with the Angostura find.

BHP's partner in both blocks 2c and 3a is Canadian independent Talisman, an operator in its own right of onshore acreage, the Eastern block, where it has just completed a 320 sq km 3D seismic programme, the largest ever undertaken in the Trinidad land area. Talisman holds 65% in the block to state company Petrotrin's 35%, and will drill three exploration wells looking for the so-far-elusive deep Cretaceous horizon at about 7,000 ft. One of the three wells will be drilled into the Miocene. Talisman's resident Manager in Trinidad, Des Norris, told *Petroleum Review* that: 'We believe the chance of finding multiple structures is quite good. The block lies along a known productive trend; we already know there is oil in the area.'

Keeping the momentum going

'Energy minister Williams is determined to create the conditions for more Angosturas and keep the exploration momentum going in both the marine and land provinces. In early May, the energy ministry announced successful bidders for three more offshore blocks (see map) - 1a in the Gulf of Paria on Trinidad's west coast, which went to newcomer Petro-Canada; 3b off the north east coast awarded to a company that will also be new to Trinidad - US independent Kerr McGee, which teamed up local player, Primera Oil and Gas - and 5c, off the south east coast, granted to small Canadian independent, Canadian Superior, which already holds one near-shore south east coast block in partnership with state company, Petrotrin. The details of production sharing contracts (PSCs) are currently being negotiated.

In the case of five other blocks for which there was only one bid each, the ministry is holding 'discussions' with the respective companies, in order, it says, 'to arrive at acceptable proposals.'

These companies are: Petro-Canada (block 1b also in the Gulf of Paria) ; EOG Resources/Primera Oil and Gas (block 4a, offshore the east coast) and BHP Billiton and partners Total and Talisman for blocks 23a, 23b and 24 (in deep water north east of Tobago).

In the case of block 22, north of Tobago, neither of the two bidders , Petro-Canada or Norsk Hydro, appears to have satisfied the ministry's minimum conditions and talks are taking place to see which one can be persuaded to do so.

A tenth block, 2ab, which attracted most interest was, ironically, not awarded to anyone and will be brought back later.'

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Mexican oil and politics don't mix

Mexico needs to make very substantial investments in exploration and production to counter the decline in its proven oil and gas reserves. However, it is stymied from securing capital for these investments by two seemingly insurmountable political barriers, writes *Judith Gurney.*

On the one hand, there is Article 27 of the Mexican Constitution which ensures state ownership of all hydrocarbon reserves, thereby denying state oil company Pemex access to domestic or foreign equity financing. Potential investors, especially foreign companies, are disinclined to invest in Mexican oil and gas projects since they are denied the right to book and own any reserves which their investments might result in, and therefore the profits from these.

On the other hand, there is the dependence of the Mexican Government for more than a third of its income on the state oil company. Pemex surrenders more than half of its revenue to the government in taxes. In 2003, for instance, it paid taxes of $35bn – some 61% of its revenue. It is therefore largely dependent on loans and debt to raise investment capital.

Value of oil

Pemex was established in 1938 at the time of the nationalisation of the foreign oil companies then operating in Mexico. Historically, it has focused its attention and available investment capital on oil, presumably encouraged to do so by the government as oil is Mexico's primary export commodity and a significant source of foreign exchange. In past years, much of the profits of oil exports went to pay off interest on Mexico's massive foreign debt.

Currently one of the world's major oil producers and a major supplier of crude oil to the US, Mexico's oil production had been at a relatively constant level for several years. In 2003, production was estimated at 3.8mn b/d, with 2.05mn b/d going to the domestic market and 1.75mn b/d exported, of which 1.6mn b/d went to the US.

Roughly two-thirds of Mexican production is a sour, heavy crude, ranging from 19° API to 22° API, coming from the Bay of Campeche in the Gulf of Mexico. Campeche contains the Cantarell field, located about 56 miles offshore, one of the largest fields in the world with an estimated 35bn barrels of oil originally in place in several sub-fields. Cantarell began production in 1979.

In the late 1990s alarm bells sounded when a disastrous fall in well productivity began in the Cantarell field as a result of a dramatic decline in reservoir pressure. Pemex responded with an enhanced oil recovery (EOR) plan designed to increase reservoir pressure through massive injections of nitrogen. Although Cantarell output has recovered somewhat as a result of this EOR plan, this is only a band-aid measure. Analysts expect Cantarell's output from fields under production to decline within the next decade.

The threat to Mexico's oil production is apparent in the country's 20-year decline in proven oil reserves. Statistics on these reserves vary, reflecting draw down and judgment regarding accessibility. (Pemex, dependent on loans to acquire capital for investment, offers future production as collateral for such loans and has been prone to exaggerating the production potential of its oil reserves.) *The BP Statistical Review* lists proven reserves of 48.3bn barrels in 1982, with a rise in the early 1990s and a fall by 2001 to 26.9bn barrels. In late 2002 Pemex revised its estimate downwards to 12.6bn barrels, apparently to comply with US SEC filing guidelines regarding commitment for exploration in the short-term. It later raised its estimate to 15.7bn barrels, with ultimate potential reserves, including crude oil, condensate, NGLs and refinery gain, as 40.6bn barrels.

With reserve replacement running at only 21%, there is no doubt that the current output level cannot continue for long without the discovery and development of new oil reserves.

Pemex is well aware of this situation. Early this year its Director, Raul Munoz, announced the company's intention to raise reserve replacement to 75% by 2006, and to 100% by 2008, and to increase production to 4mn b/d. These goals will require near-term capital investments of some $45.3bn on exploration and production and $16.1bn for refinery upgrades, with the necessary funds presumably being raised mostly through new debt issues. Some of this investment will be expended on drilling platforms and pipelines in shallow waters in the Campeche Bay, and some in Tabasco offshore fields as well as on the onshore Veracruz and Chicontepec fields. Pemex has awarded some contracts for the construction of an estimated 37 offshore drilling platforms,

Year	Production	Consumption
1992	26.2	28.9
1993	25.4	26.5
1994	25.9	27.0
1995	26.6	28.1
1996	28.0	28.6
1997	31.7	32.3
1998	34.3	35.4
1999	37.2	37.4
2000	35.8	38.5
2001	35.3	39.0
2002	34.8	42.1
2003 est	35.4	45.4

Sources: BP Statistical Review, *Cedigaz, Wood Mackenzie*

Table 1: Mexican natural gas production and consumption, 1992–2003 (in bn cm)

mostly in the Campeche Bay, and also for some deepwater drilling and production platforms.

The main hope for Mexico's oil sector lies in its deep waters. Munoz has estimated that 80% of Mexico's potential new oil reserves lie in unexplored deepwater fields, with large reserve deposits believed to exist in Cantarell. However, Pemex lacks the infrastructure, technology, experience and know-how for deepwater exploration and development, and needs help from foreign deepwater oil companies to compensate for these shortcomings. And it needs this help soon, as even experienced deepwater operators require years to find deepwater fields and to develop these to production.

Pemex is said to be talking currently to a number of foreign deepwater companies regarding these issues. But how can it persuade such companies to get involved, given the political barriers to offering them a chance to book any reserves found as a result of their efforts?

MSC initiative

Pemex hoped it might have a solution to the problem of attracting foreign companies to assist in its energy sector with the so-called Multiple Service Contracts (MSC) it began to offer in late 2003 for projects in the Burgos gas field.

The threat facing Mexico's gas production requires more immediate attention than that facing the oil sector. Mexico's proven gas reserves have steadily declined over the past two decades, from an estimated 2.15tn cm in 1982 to an estimated 0.25tn cm in 2002, according to *The BP Statistical Review*. As with oil, Mexico has the potential of ample gas reserves to meet domestic demand as well as for export, but sizeable investment is required to bring these into production. Although there are several significant onshore fields, one-half to two-thirds of the remaining reserves are said to lie offshore on the Campeche Shelf, mostly in deep waters.

Gas production, which had been nearly flat for several decades, began to rise in the late 1990s. However, the increase, to around 35bn cm/y, failed to keep abreast with the rise in domestic demand, which began to increase at the same time largely due to burgeoning demand from the electricity generating sector. Up to then, more than half of Mexican gas production was consumed by Pemex in its oil field operations and as feedstock and fuel for its petrochemical plants. Another third went to the industrial sector and only a fraction to the residential and commercial sectors.

Even before the domestic demand increase, Mexico was importing gas from the US, despite an import tax. When this tax was lifted in accordance with the terms of the North American Free Trade Agreement (NAFTA), imports surged from 3.11bn cm in 2000 to 7.45bn cm in 2002. Imports now meet more than 15% of Mexico's annual gas consumption of some 45.3bn cm. The several proposals for the construction of LNG terminals on Mexico's east and west coasts for the importation of gas from sources other than the US are not well advanced, and the amount of gas involved would do little to ease the Mexican gas shortage.

In 2003, Pemex launched a plan aimed at increasing gas production some 80% by 2008. It has raised funds for this from several sources, including the Japan Bank for International Cooperation. The plan focused on doubling production in the northeast Burgos Basin, which currently accounts for some 25% of Mexico's gas output. Pemex studies suggest that Burgos contains 2.1tn cf of proven reserves and 1.2tn cf in additional probable reserves. Increased production of this gas would allow industrial and power plant boilers to use gas instead of high sulphur fuel oil, a significant pollutant.

Pemex planned to achieve this goal with the assistance of foreign companies by offering them MSCs, seen as a first step in breaking the ban on private investment in Mexico's gas and oil industry. Under the MSC terms, companies would be responsible for financing a project, and they would be paid in cash for the work performed and the services rendered. But they would not be allowed to book and own any gas reserves that they found and developed, nor have a share in the profits of the production of these reserves.

Pemex put seven Burgos blocks up for bids at the end of 2003. This offering was, at best, a qualified success. Contracts were awarded for five of the blocks, with only one of these attracting more than one offer, and with the two largest blocks failing to attract a single bid. In addition, the five contracted blocks are not considered to hold significant reserves. More significantly, none of the supermajor oil companies put in bids. Repsol-YPF, Petrobras and Tecpetrol (a unit of Technit) were the most well-known bidders; the rest were much smaller Japanese, Chinese, Mexican and US companies.

It would appear that MSCs are not going to be the answer to finding the investment so badly needed by Mexico for its oil and gas industry.

No solution in sight

The election in 2000 of President Vicente Fox as a representative of the Conservative Action Party (PAN) was hailed as the beginning of the end of 71 years of rule in Mexico by the Institutional Revolutionary Party (PRI). Expectations were high that he would institute reforms to enable Pemex to raise the capital necessary for investments in the energy sector.

To date, President Fox – whose term ends in 2006 – has been unable to get reforms passed by a Mexican Congress dominated by the opposition. He has failed to get measures to reduce Pemex's tax burden by raising more revenue in general taxes, such as income tax and VAT on goods and services. He has also been unable to secure enough votes to get electricity sector reforms passed, reforms viewed by many as a precursor to broader energy policy changes to allow private participation and investment in the state-run energy sector.

These failures do not bode well for the future of Mexican oil and gas. ●

The LNG 'scam'

The shortage and high prices of natural gas in the US encouraged several major oil and gas companies to see Baja California – the Mexican peninsula south of California which is geographically isolated from the rest of Mexico by water – as an ideal site for the construction of LNG regasification terminals bringing LNG from the Asia-Pacific region to be shipped by pipeline to gas-starved southern California. This strategy would allow them to circumvent California's notoriously stringent environmental and construction regulations regarding the building of LNG terminals on the California coast.

Plans for four LNG terminals, all within 60 miles of the California border, were progressing when resistance erupted from Mexican environmental activists, fishing interests, real estate interests and politicians who saw these terminals on Mexican soil solely as a back-door way of supplying gas to California. Protests forced the cancellation of well-advanced projects by ConocoPhillips-El Paso for a terminal in Rosarito, and one by Marathon for a terminal in Tijuana. Opposition has now become more strident regarding a proposed Shell-Sempra Energy terminal at Ensenada and a ChevronTexaco plan to construct an offshore terminal near the Coronado Islands. ●

Looking forward to project financing

Liz Bossley of the Consilience Energy Advisory Group (CEAG) takes a closer look at E&P project financing using the forward oil and gas price curves.

The 1990s saw a frenzy of merger and acquisition (M&A) activity in the oil and gas exploration and production (E&P) sector. There were two particular consequences of this trend – a large number of high quality executives found themselves without jobs, and a range of potentially economic projects fell below the radar screen of the new, giant companies.

Inevitably, some of these experienced executives have banded together to evaluate these shelved projects with the help of new technology and have decided to form their own companies to exploit these neglected assets. But how do new companies with no track record and no assets raise the finance to develop even low risk projects?

The traditional sources of funding for E&P companies are:

- the retention of cash flow from producing assets (eg by not paying a dividend to shareholders),
- borrowing money, or
- raising equity.

However, new entrants to the market for whom these traditional funding sources are unavailable or unattractive have a fourth option available to them, namely, using the forward oil and gas price curves to finance development expenditure. This tool can change when and how much borrowing is required or when and how much equity is raised.

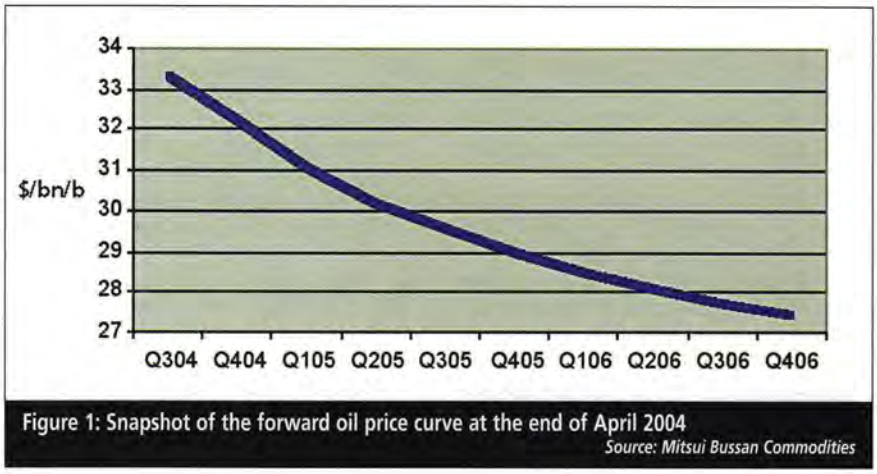

Figure 1: Snapshot of the forward oil price curve at the end of April 2004
Source: Mitsui Bussan Commodities

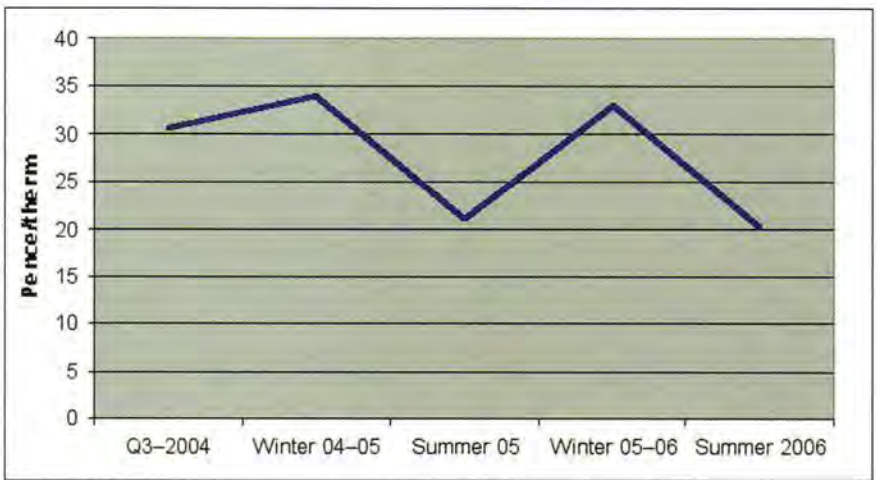

Figure 2: Snapshot of the forward gas price curve at the end of April 2004
Source: Argus

Oil and gas prices

When a company considers developing an oil or gas field, its decision will be based on its view of the future oil or gas price. The company may have its own oil and gas price forecast but, for the purpose of analysing project economics, typically companies use a range of price scenarios. However, a forward price curve exists which allows companies to lock in the future price of oil and gas today, dispensing with the need for questionable future price assumptions or forecasts.

Project financing off the curve is achieved by locking in an attractive forward oil or gas price and using this hedge to collateralise a loan or to advance cash-flow from the sales leg of the hedge to develop the project.

Figures 1 and **2** show a snapshot of the forward oil and gas price curves at the end of April 2004. Both curves exhibit 'backwardation', although in the case of gas this is disguised by the seasonality of prices. Backwardation is where prices for delivery in the near future are at a premium to prices for delivery further forward. Ordinarily, when commodity prices are in backwardation there is a disincentive for producers to sell or hedge forward.

However, the good news for companies attempting to raise project finance is that, even allowing for backwardation, the prices on offer from the forward curve are well in excess of the conservative base case price assumptions currently being employed by companies considering oil and gas field developments.

For example, the price of oil for delivery in 2006 is currently trading well in excess of $27/b. Although this looks unattractive compared with prompt prices of around $33/b, it is still well in excess of corporate scenario planning prices of $20–$22/b. Small E&P companies are prepared to live with a lot of backwardation, if the alternative is not to buy an asset or develop a project for lack of funding.

How it works

There are several ways of financing a project using the forward price curve, but the simplest for E&P companies with no trading capability is to start by selling an OTC (over the counter) for-

ward swap. A potential producer planning to develop a field in this situation can shed to a market maker a floating index of prices that will unfold in future years and gain a known fixed price today. The actual price of oil and gas for production and delivery in some future time period is unknown and can be represented by a floating price index. For example, the price of a cargo of oil loading in June 2006, will in fact be based on some sort of average of the prices that will be published in journals during the month June 2006, assessed by reference to market deals done on or around that future time period. This is generally referred to as 'a floating price' in swap parlance. In other words, the producer can swap a floating price for a fixed price, using the OTC swaps market. When physical oil or gas flows in the future, it will be sold at the floating price on the day. So, the result is that the producer has 'hedged' its future oil or gas production at a fixed price.

Selling the expected future revenue stream from a development project, or a producing cash cow asset, into the futures or OTC market can be used to demonstrate to lenders or shareholders that the price element of future cash flow from the project is not at risk, hence facilitating the traditional financing methods. Or it can be monetised directly from derivative market players to provide cash now, to eliminate the need for going to lenders at all. Not only is this a source of funding, but it is a mechanism for unbundling oil price risk, with which E&P companies are ill-equipped to deal.

Figure 3 shows a schematic representation of one option of how the project financing model can work – although there are other models, depending on the parties involved and the risk characteristics of the project.

In this example the deal is arranged through a special purpose vehicle (SPV) company. This may be done to isolate the project financing deal from other creditors of any or all the counterparties involved.

In this model:

- Physical oil flows away from the producer to a refiner for a floating price.
- The loan and the loan repayment transfer from and back to the bank based on a fixed price.
- This bank loan is collateralised by the transfer of floating price risk to the swaps provider in exchange for a fixed price to the producer.

Each of the couterparties in this example – the bank, the swaps provider and the physical oil buyer– are all different companies. In fact, the lender, the swaps provider and the physical cargo buyer may all be one and the same party. Or the lender and the swaps provider may be the same company, while the physical oil may be sold to a third party directly by the buyer, with or without using an SPV company.

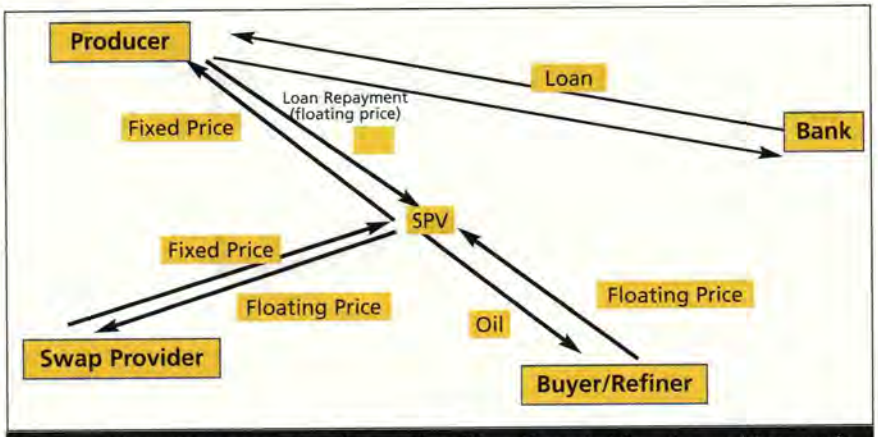

Figure 3: Schematic representation of one option of how the project financing model can work
Source: CEAG

Managing risk

Shedding price risk is the easy bit. However, managing other project risk – 'Is the reservoir analysis accurate?', 'Can the small company handle the development phase?' – in a manner that will encourage a bank to make a loan or a derivative provider to advance cash flow, is more difficult. Banks will typically only lend to new, small producers against oil already in production or at an advanced stage of development. The choice of price risk management partner can have a role to play in reassuring lenders that the project risks are being managed too. In addition, if the price risk management partner is also the lender and is also the company buying the physical future oil stream, the possibility exists of offsetting some of the technical imperfections of financing deals through which profit can leak.

The ideal situation is where the seller of the asset is involved in the financing of the deal. When the seller of the asset to the small producer is a major oil or gas producer, the lending bank will be reassured by the presence of an established financially secure entity who can be quizzed very robustly about the quality of the project. For the asset seller, facilitating new financing sources increases the range of buyers for the assets they are trying to sell.

Among recent asset deals that have employed variation of this financing technique have been BP sale of Forties assets to Apache and Shell's sale of Montrose, Arbroath and Arkwright to Energy North Sea. Both Tuscan and Acorn used elements of forward curve pricing in the financing of the Ardmore field. The banks who appear most open to innovative financing techniques are Mitsui, Macquarie and Standard Bank, although banks in general will typically stop short of taking a *de facto* equity share of the project, by accepting project risk – ie if the asset fails to produce the banks still want repayment of the loan or performace on the forward price swap.

Examples of forward curve project financing for European gas projects are more difficult to identify because the forward gas curve is less liquid and the market is more fragmented across a range of regional gas price indices. However, CEAG hears that there are gas deals of this type currently under discussion in the Gulf of Mexico using the Henry Hub forward gas price curve.

Hurdle rates

Even the large companies have finite resources and project financing off the curve can allow a lowering of the hurdle rate to allow the development of additional projects for which traditional financing is not available. Asset teams or regional offices within large companies whose projects have failed to clear internal corporate hurdle rates can, in a sense, also be regarded as small E&P companies. Such asset teams can effectively expanding the pot of corporate funding using this additional source of financing to a level where their own pet projects can be developed.

Obviously, the hurdle rate should not be set so low as to allow projects of questionable profitability to be developed. A project is only worth developing if the economics are robust – an innovative source of funding will never justify expenditure on a marginal project.

When it comes to financing oil and gas projects, there is no free lunch... but there may be a better restaurant!

Too much of a good thing?

The concept of front end loading (FEL) is now well established as best practice in the management of major oil and gas field developments. The idea is that time and effort spent improving the technical definition of a project will reap dividends later in terms of faster and cheaper execution. However, Strategic Decisions Group's *Nick Lowes*,* Senior Engagement Manager, and *Jan Paul van Driel*,* Partner, ask whether an excessive focus on project execution might actually be destroying value?

Deciding how much time and resources to expend on the pre-sanction phase of a large oil/gas development project is not straightforward. Typically, senior management and joint venture partners will be pushing for rapid progress, while the host government will want early revenues... but are the risks of early sanction too high?

Conventional project management practice answers this question by assessing the level of technical definition achieved.

- Front end loading (FEL) reviews evaluate completeness of technical definition and corresponding project uncertainty (cost, schedule, quality etc) and compare these with industry benchmarks.
- Poor review results indicate that better definition is needed before the project should progress.

Such reviews, if acted upon, can certainly help to reduce variability of project execution outcomes. However, if we look back at the industry's performance over the last decade we see that over half of all sizeable fields brought onstream have taken 10 years or more to get to first production from discovery, and around a third have taken upwards of 15 years. By contrast it took just eight years to put a man on the moon back in the 1960s!

This unenviable record suggests that for many upstream developments the critical schedule drivers are not related to post-sanction execution, but to the challenges in finding economically viable political, commercial and technology solutions to complex reservoir, infrastructure and marketing problems.

Project value profile

A limitation of the FEL benchmark review is that FEL scores do not directly measure the value created by accelerating or delaying sanction. Perhaps recognising this, project leaders seem somewhat ambivalent about conventional FEL metrics. Many large projects, regardless of operator, get only moderate to poor review results at the time of sanction[1,2] – this seems a natural consequence of their inherent complexity. And yet they are progressed to execution anyway. Are management misguided, or are is it responding, either consciously or unconsciously, to other project value drivers?

In some situations, holding a project until a generic or pre-determined level of technical definition is achieved can destroy value.

- *A market opportunity is missed.* A transient market opportunity might be critical to the project's business success, especially for gas projects.
- *A construction window is missed.* For example, construction activities

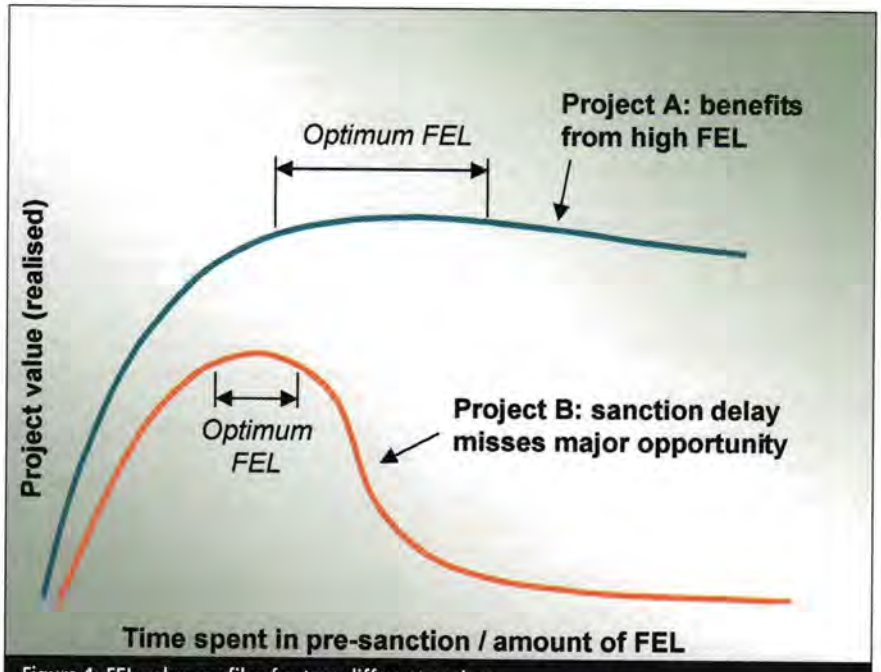

Figure 1: FEL value profiles for two different projects

may be dependent on seasonal weather patterns, such as the winter closure of access canals to the Caspian Sea.

- *A commercial opportunity is missed.* For example, an opportunity to acquire specialist equipment or services at favourable rates (deepwater drilling rigs, heavy-lift vessels).
- *Contractual obligations are not fulfilled.* Contract terms with governments can have onerous penalties if schedule commitments aren't met.
- *Strategic objectives are endangered.* There may be enormous value from being a first mover in a new region, or in sanctioning a project before farming out equity.
- *Flexibility is overly constrained.* Option value may be lost by forcing an excessive level of technical definition.

So, it's important to recognise that each project has its own unique value profile, which defines the optimum level of FEL. To illustrate the point **Figure 1** considers a couple of very different projects.

Project A is a conventional oil project in a mature producing region, where the risks are principally technical. Increasing the time spent on definition adds value up to an optimum level, then declines relatively uniformly as delay in execution starts to erode NPV (net present value). By contrast, Project B displays one or more of the schedule imperatives described above. In this case less time should be spent in the FEL phase, as delay to sanction will have disastrous consequences.

Value-based sanctioning

If the FEL review provides only part of the picture, then how do we determine the optimum time to sanction a project? An alternative approach focuses entirely on value.

- Additional project definition (FEL) is justified if the resulting reduction in uncertainty adds net 'risked' value, ie when determined probabilistically.
- If the cost and delay to sanction of further definition destroys value, *then the decision to progress the project or not should be taken now.*

We term this net value impact the *value of definition* (**Figure 2**). The key to its assessment is to recognise *all* sources of uncertainty, so it is essential to keep the context broad to capture both project and wider (basin/play, business unit) implications. As a result, there will be significant ranges of uncertainty around the results, and it would be fortuitous if one course of action (sanction or delay) proved better under all scenarios. Nevertheless, the preferred course is usually apparent.

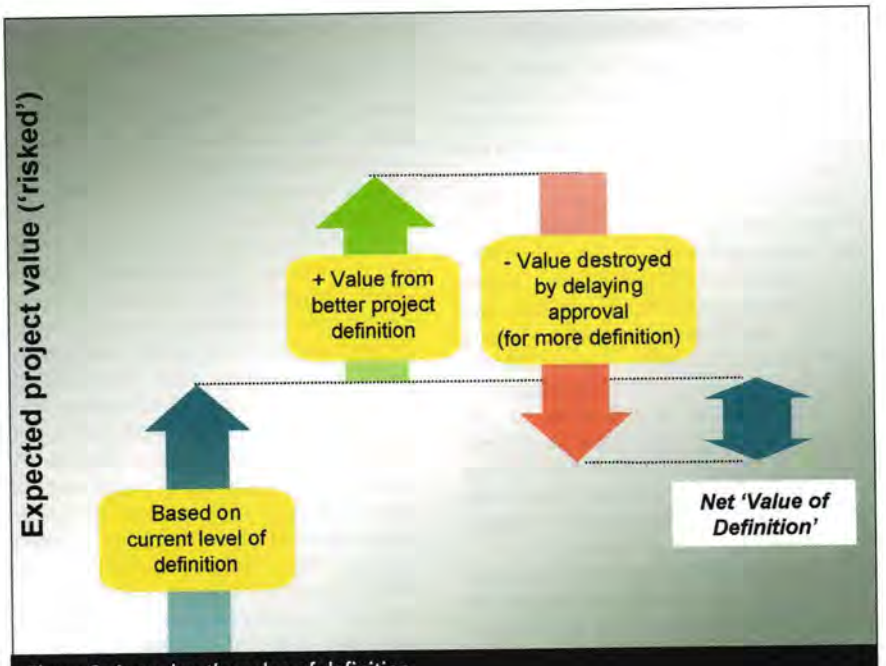

Figure 2: Assessing the value of definition

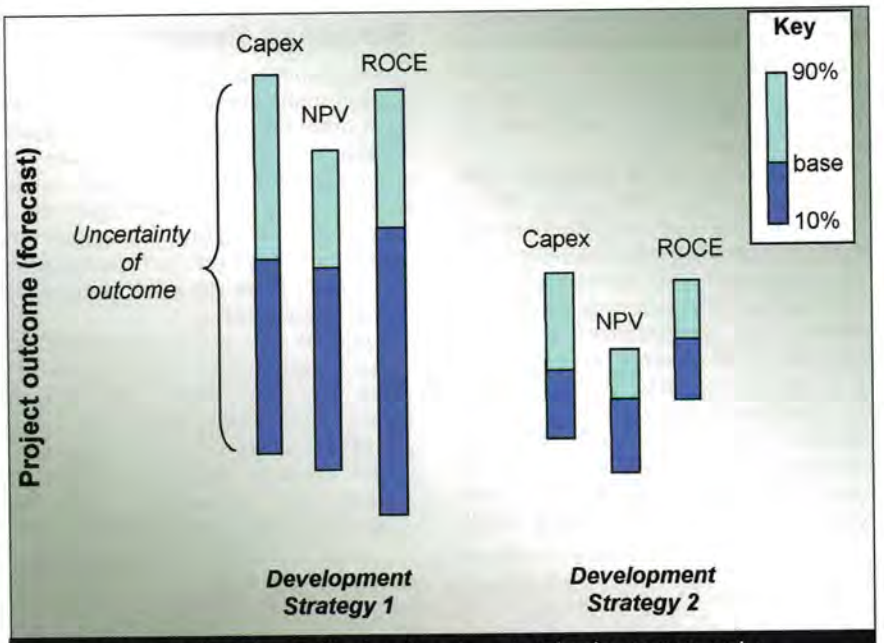

Figure 3: Comparative value profiles for alternate project development strategies

But this approach can raise a problem. What do we do if our FEL benchmark metrics suggest project definition is too low (and uncertainty is too high), but further delay in sanction is seen to destroy value? In this case it is important to identify up front what can and should be done to alter course as different uncertainties become partially or fully resolved. This requires the creation of a dynamic development plan, or *roadmap*, which retains the required degree of flexibility as we move forward.

After completing such a value-based readiness assessment, project and asset managers will:

- have greater insight into the project's key value drivers;
- understand whether the *right* level of definition has been achieved *for this specific project;*
- be able to clearly demonstrate to senior management and partners whether the project should be progressed.[3]

Joint venture (non-operating) partners will:

- have a transparent *value basis* for making internal recommendations;
- be better aligned with the operator on the investment decision.

Embracing uncertainty

So, we've managed to figure out whether we should sanction now or whether we need better definition. But how do we know we're sanctioning the 'right' project?

One of the consequences of FEL-based thinking, and its emphasis on improving definition, is the belief that uncertainty is inherently bad – something which must be minimised, and ideally eradicated entirely. Taking **Figure 3** as an example, a conventional FEL review would score Development Strategy 2 more highly due to the lower uncertainty of outcome. In fact, the need to pass a review hurdle may drive project teams along this route, even though Project Strategy 1 clearly has more value but is riskier.

The same line of thinking leads project teams to equate uncertainty to (only) downside risk,[4] and to the need for detailed plans to limit or avoid all uncertainties. This misses the obvious point that uncertainty also has an upside. Even where the upside is recognised it is often treated serendipitously rather than something to be captured through project planning. The result is poor decision-making, which fails to realise full asset value.

It is also useful to recognise that large oil and gas companies, with a diverse portfolio of opportunities, are in theory risk neutral on the value of an individual asset. This means there is no *inherent* value in reducing uncertainty around the development outcome, provided it is correctly assessed, and provided the project is not so large as to significantly impact the company's overall risk profile. As a simple example, this means that a large company should prefer to have a 50% chance of making $100mn and a 50% chance of making nothing than to be certain of making $40mn from an asset. This does not mean the company should be unconcerned about risk, but rather that any activities to reduce uncertainty should only be undertaken if they increase the expected value (EV) of the project.

In practice most companies are not risk neutral on meeting their development targets. This is in part because uncertainty is generally poorly communicated to the investment community, with the resulting loss of credibility once (single point) forecasts are missed. Notwithstanding this, a company will almost always have a much higher risk tolerance than the individual project or asset manager. The project manager, primarily held accountable for delivery to plan, will trade off value for 'certainty' in order to meet his/her performance commitments. Trade-offs between execution and value are therefore better made higher up the organisation.

Retaining flexibility

A single-minded focus on reaching a predetermined level of definition can have other impacts. One of the biggest threats to a project's business success is the early destruction of option value. By narrowing down too quickly on a base case solution, one that appears to meet the project hurdle requirements, the project team closes off potentially higher value options.

Some of our options will have no value, because we would never choose those solutions under any circumstances. But others may have large additional value over the base case under certain scenarios – reservoir, commercial, technology etc. By retaining a degree of flexibility in our development plans, and, for example, by accelerating certain appraisal or commercial activities, we may be able to capture this value before the opportunity is closed off.

A good example of this thinking is provided by ExxonMobil's Early Production Systems[4] – mobile FPSOs built on spec and moved quickly to new field locations to capture both early production and early reservoir learnings. The EPS creates options for future development of the field, which simply wouldn't exist if a more conventional development approach was followed.

This requires a very different mode of thinking by the project leadership – the willingness to base project planning around learning events, and to take forward multiple contingent development paths. It remains to be seen whether future project leaders will take up this challenge, or whether they will continue to destroy value through excessively rigid early-stage planning.

**Nick Lowes is a Senior Engagement Manager at Strategic Decisions Group. Jean Paul van Driel is a partner. To find out more about the company: visit* www.sgd.com

1. The term 'sanction' is used here to mean the final investment decision (FID) by the equity partners.
2. 'Mega-field development requires special tactics, risk management', Offshore, June 2003.
3. This will typically also require a demonstration that the plans and resources are in place to move into execution.
4. 'De-risking the development', *Offshore Engineer*, November 2003.

Letter to the Editor

Dear Sir

I read your article on 'Oil field mega projects 2004' in Petroleum Review *[January 2004].*

The question which poses itself is, given the gradually increasing certainty of forecasts and the big question mark you paint over the period 2007 and beyond, is there to be an emergence of a truly long-range market in oil futures to extend to this point?

I submit that this would be a beneficial step, since prices are known to focus politicians' minds (and those of their voters). Presumably the pension funds would be investing in such oil futures?

Of course there is always the possibility that some totally new type of energy source may be found, fossil-based or otherwise – as our group believes could be the case. And, if it could be brought onstream fast enough and machinery adapted to operate from it, who knows, chaos could be averted.

Yours,
Stephen Lawrence,
Committee for Future Energies
Cambridge, UK
www.future-energies.org

If you wish to comment on any issues raised in *Petroleum Review*, please write to Chris Skrebowski, Editor, *Petroleum Review*, 61 New Cavendish Street, London W1G 7AR, f: +44 (0)20 7637 0086 e: cs@energyinst.org.uk

Towards Zero Carbon: Sustainability in Practice

Jointly organised by the Energy Institute and the Solar Energy Society (UK-ISES)

Tuesday 21 September 2004

Infolog Conference Centre, Russell Square House, 10–12 Russell Square, London WC1B 5EH, UK

Following on from last year's successful conference, held jointly by the Energy Institute (EI) and the UK Solar Energy Society (UK-ISES), the EI is pleased to announce the continuation of this discussion with a second conference entitled *Towards Zero Carbon: Sustainability in Practice.*

Previously, this conference focused on emerging technologies, and looked at possible synergies that may enhance the take-up of renewables in the future. This year, the emphasis will be on existing technologies, and the steps that need to be taken to increase the uptake to levels required by government targets.

With speakers providing updates on photovoltaic applications, low energy building design, solar thermal (passive and active), biofuels, wind and combined heat and power, the morning will provide the technical input to the day, examining issues such as cost, availability, practical case studies and technical constraints. In addition, the conference will examine the softer issues of implementation, most notably: public awareness and acceptance; the availability of necessary skills and knowledge; the need for innovation; and policy and planning issues. Without these issues being properly addressed the implementation of renewables will continue to be slow.

Drawing together individuals with vast experience of new energy systems, together with those at the forefront of technology developments and policy development, this is a conference that should not be missed. It will be of interest to anyone involved in the supply, utilisation and management of energy in the UK in both private and public sectors, and who wish to understand how these low carbon technologies can be achieved in practice.

This conference provides a forum in which to examine cross-technology issues without partisanship, and aims to inspire delegates to tackle the major obstacles in order to develop this emerging industry.

Speakers include:

- Dr Tony Day – London South Bank University
- David Olivier
- Professor Sue Roaf – Oxford Brookes University
- William Orchard – William Orchard & Partners
- Dr Nick Banks – SEA/RENUE
- Louise Kingham, Energy Institute
- Dr Patrick Devine-Wright, De Montfort University
- Gordon Taylor, Independent Consultant

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Emerging Asia drives world energy use

Worldwide energy consumption is projected to grow by 54% by 2025, according to the reference case projection of the *International Energy Outlook 2004 (IEO2004) report recently published by the *Energy Information Administration (EIA).***

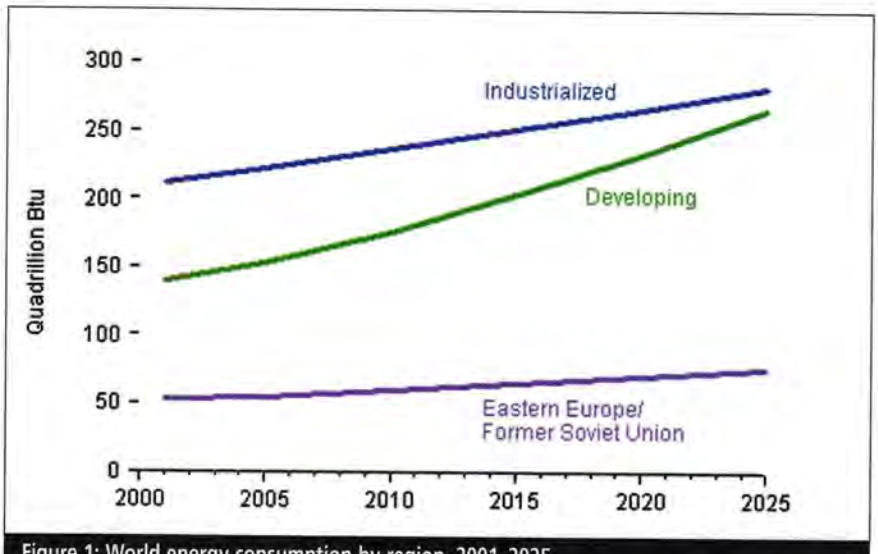

Figure 1: World energy consumption by region, 2001–2025
Source: EIA, International Energy Outlook 2004

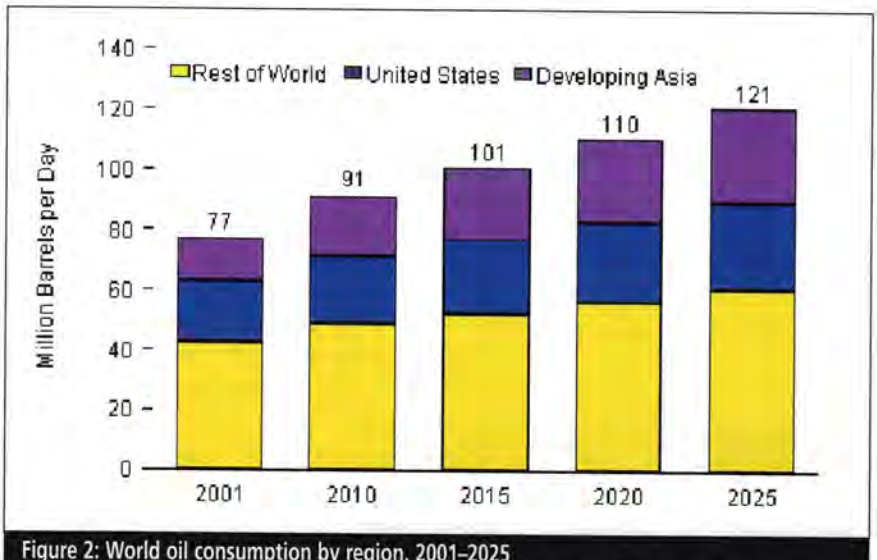

Figure 2: World oil consumption by region, 2001–2025
Source: EIA, International Energy Outlook 2004

The *IEO2004* report shows strongest growth in energy consumption among the developing nations of the world, especially developing Asia (including China and India), where robust economic growth drives the increase in energy use over the projection period (see **Figure 1**). Energy use in the developing world increases by 91% over the forecast period.

In contrast to the developing world, slower growth in energy demand is projected for the industrialised world, which experiences a 33% increase in energy use between 2001 and 2025. Generally, the nations of the industrialised world can be characterised as mature energy consumers with comparatively slow population growth. Gains in energy efficiency and movement away from energy-intensive manufacturing to service industries result in the slower growth in energy use.

Energy use in the transitional economies of Eastern Europe and the former Soviet Union is expected to grow by 42% over the forecast period. Slow or declining population growth in this region, combined with strong projected gains in energy efficiency as old, inefficient equipment is replaced, leads to more modest growth in energy demand than in the developing world.

World oil prices rose by almost $10/b over the course of 2002 and remained high throughout 2003. Oil prices are expected to fall after 2004 to $25/b in 2002 dollars and then rise slowly to 2025, reaching $27/b in 2002 dollars, comments EIA. World oil use increases from 77mn b/d in 2001 to 121mn b/d in 2025 in the report's reference case. Much of the increase (60%) in oil demand is expected to occur in the US and in developing Asia (see **Figure 2**). Although Opec producers are expected to be the major suppliers of increased production requirements, non-Opec supply remains competitive, with major increments in supply coming from offshore resources, especially in the Caspian Basin, Latin America and deepwater West Africa.

Report highlights

Other report highlights include:

- *Electric power use* – World net electricity consumption nearly doubles

over the projection period, from 13,290bn kWh in 2001 to 23,072bn kWh in 2025. Strong growth in electricity use, averaging 3.5% per year, is projected for the developing world, where robust economic expansion drives demand for electricity to run newly purchased home appliances for cooking, air conditioning, space and water heating and refrigeration. For the industrialised world and the EE/FSU, where electricity markets are a lot more mature, slower average growth rates of 1.6% and 2% per year, respectively, are projected.

- *Natural gas demand* – Natural gas is the fastest growing source of world primary energy in the report's reference case. Over the 2001–2025 forecast period, consumption of natural gas is projected to increase by 67% to 151tn cf by 2025. The projection for natural gas use is lower than in last year's outlook, when gas demand was expected to climb to 176tn cf in 2025 (see **Figure 3**). The lower forecast this year is the result of slightly lower assumptions for worldwide economic growth, a slower projected decline in the world's nuclear power generation, and concerns about the long-term ability of natural gas producers to bring sufficient resources to market at prices competitive with those of other fuels.

- *Coal consumption* – Coal remains an important component of the world's electricity markets and is expected to continue to dominate many national electricity markets in developing Asia. Currently, of the coal consumed worldwide, 64% is used for electricity generation; and in almost every region of the world, power generation accounts for most of the projected growth in coal consumption (see **Figure 4**). Where coal is used in the industrial, residential, and commercial sectors, other energy sources – notably natural gas – are expected to gain market share. One exception is China. With abundant coal reserves and limited access to alternative fuels, coal continues to be the most widely used fuel in the country's rapidly growing industrial sector.

- *Nuclear power generation* – The worldwide, electricity generation from nuclear power is projected to increase from 2,521bn kWh in 2001 to 3,032bn kWh in 2020, before declining slightly to 2,906bn kWh in 2025. The nuclear power forecast is higher than in last year's outlook,

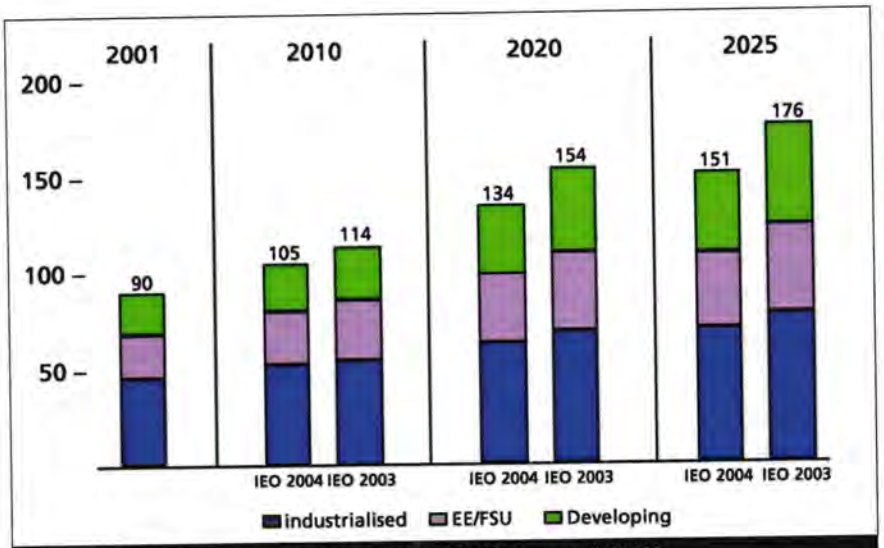

Figure 3: Natural gas consumption by region, *IEO2004* versus *IEO2003*
Source: EIA, International Energy Outlook 2004

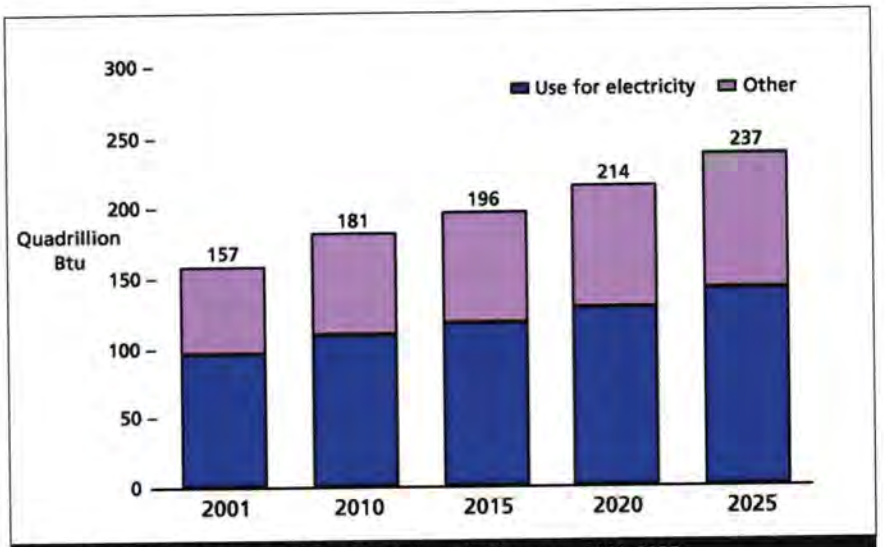

Figure 4: World coal consumed for electricity and other uses, 2001–2025
Source: EIA, International Energy Outlook 2004

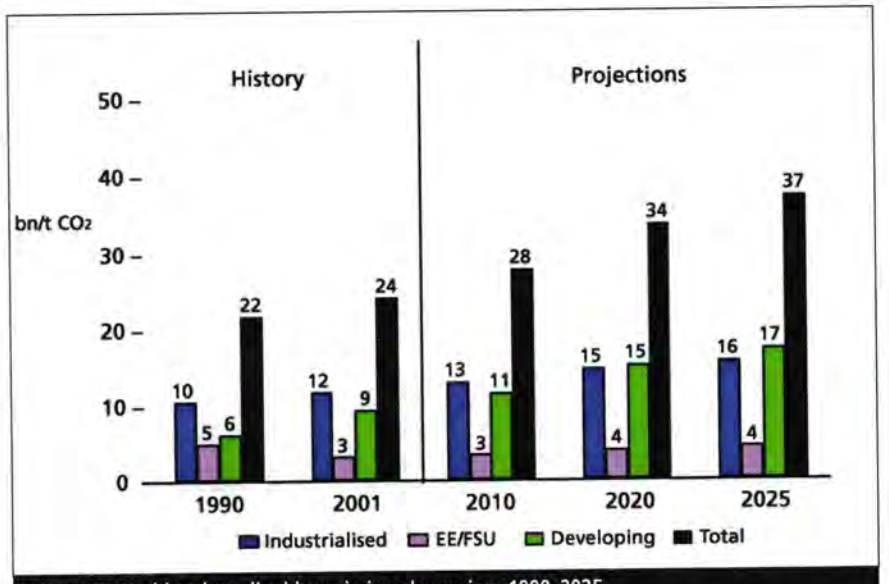

Figure 5: World carbon dioxide emissions by region, 1990–2025
Source: EIA, International Energy Outlook 2004

because the prospects for nuclear power have been reassessed in light of higher capacity utilisation rates reported for many existing nuclear facilities and the expectation that fewer retirements of existing plants will occur than previously projected. The largest increase in nuclear generation is projected for the developing world, where consumption of electricity from nuclear power increases by an average 4.1% per year over the forecast horizon. Developing Asia is expected to see the greatest increases in regional nuclear generating capacity, accounting for 96% of the total projected growth in capacity in the developing world.

- *Renewable energy* – Moderate growth in the world's consumption of renewable energy sources is projected in the report's reference case. Much of the growth is expected to result from the completion of large-scale hydroelectric facilities in the developing countries, especially in developing Asia. Among the industrialised counties, only Canada has plans to construct any sizeable hydroelectric projects over the forecast period. Much of the expected growth in renewable energy consumption in the industrialised world is projected to be non-hydropower renewables, especially wind energy in Western Europe and in the US.

- *Carbon dioxide emissions* – In the report's reference case, carbon dioxide (CO_2) emissions are projected to rise from 23.9bn tonnes in 2001 to 27.7bn tonnes in 2010 and 37.1bn tonnes in 2025 (see **Figure 5**). Much of the projected increase in emissions is expected to occur in the developing world, accompanying the large increments in energy use that is projected for the region's emerging economies. Developing countries account for 61% of the projected increment in CO_2 emissions between 2001 and 2025. Continued reliance on coal and other fossil fuels, as projected for the developing world, would ensure that even if the industrialised world undertook efforts to reduce CO_2 emissions, there would still be substantial increases in worldwide CO_2 emissions over the forecast period.

The International Energy Outlook 2004 report can be viewed on the EIA website at* **www.eia.doe.gov/oiaf/ieo/index.html

... contined from p17

To provide a TAML Level 5 junction in a new well, a pre-milled window, covered by an aluminium sheath, is installed above the orientation latch coupling. Inside, there may be a pressure-isolation sleeve to allow high differential ratings for cementing. After cementing, a deflection whipstock is inserted into the latch coupling and the wrap is dressed out. A regular directional-drilling assembly drills out the pre-milled window and the lateral hole. After drilling is completed, the whipstock is retrieved. To upgrade the well to sealed completions, the FlexRite™ System deflector is run. The FlexRite™ flexible hanger and lateral screens or liner is run, oriented, landed, and sealed into the FlexRite ™ completion deflector. This high-volume cased multilateral junction system offers superior flow volumes in a pressure isolated cased junction. This hybrid system incorporates many design features from proven systems and lessons learned from previous operations.

The initial system specifications as used in one North Sea deepwater well were:

- $9^5/_8$-inch, 47 lb/ft casing;
- $8^1/_2$-inch lateral wellbore drillout;
- 7-inch liner or $6^5/_8$-inch and $5^1/_2$-inch premium screens;
- 1,000 psi pressure rating (burst/collapse);
- $4^3/_4$ inch bore equivalent flow area through each leg; and
- maximum tool size $3^3/_8$-inch through junction.

The well had $9^5/_8$-inch casing set in the original drilling phase. The lower zone was produced through $4^1/_2$-inch tubing, and the upper zone was produced through $2^7/_8$-inch tubing. Planning included a 6-inch, short-radius horizontal into the lower zone and an $8^1/_2$-inch horizontal drilled and logged in the upper zone. The lower zone was left open hole while the upper zone was cased with a 7-inch liner cemented on bottom. A 7-inch pre-milled window joint was run in the lower build section. The upper lateral was perforated, and a dual completion installed with tailpipe in each lateral.

Workover case history

The existing well had a latch coupling installed on a packer. The MillRite™ system was inserted into the latch coupling profile and a hole milled in the casing. After milling, the system was removed and a whipstock run into the latch coupling. The lateral hole was drilled to complete a Level 2 junction.

It should be noted that a liner can be run and washed over if the well requires a Level 4 junction. Each well design may also include a FloRite™ completion system if a dual segregated or commingled completion is needed.

The key component of the dual segregated FloRite™ completion system is the dual production whipstock, which provides the deflection of one string into the lateral. A second zone is produced through the whipstock using a second string. Two full-diameter tubing strings go through the junction. Full drift assemblies may be run through the junction to either zone. This tool, when run with production packers, provides zonal isolation. Flow control is provided in the individual strings with the same tools and techniques as a conventional completion. This dual whipstock, when run with a lower main bore packer, a lateral packer, and a dual packer, provides a TAML Level 5 pressure isolated junction completion.

The well was drilled as a deviated, two-zone dual producer and produced for several years. The production water cut was increasing, and the near wellbore area in both zones had significant water coning. The produced fluid was quite corrosive and the L-80 material used in the flow wet areas had considerable corrosion. It was decided to abandon both sets of perforations and redrill the lower zone with a short-radius horizontal lateral in this zone. For the upper zone, the decision was made to drill, log, and run and cement a liner, and perforate selected intervals. It was necessary to allow the drilling and isolation of another lateral for additional production or to replace the lateral in the case of water cresting.

The well was successfully completed and is currently producing at acceptable rates with lower water cuts than before the recompletion. The completion renewed the well with new corrosion-resistant tubulars, thus extending the economic life of the well. Reperforation in the lower zone did not reduce the water cut, but redrilling as a horizontal well successfully controlled water production.

It is also possible to run the FloRite™ system which consists of a cemented lateral liner and completion packers in the lateral.

Reference

DeMong *et al* (2003). 'Casing design in complex wells: the use of expandables and multilateral technology to attack the size reduction issue', OGJ High Tech Wells Conference, Galveston, Texas.

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Good management of hydrocarbons can offer significant cost savings for the operator and assist in reducing environmental impact. This new document focuses on current best practice in the areas of operation, accounting, hydrocarbon measurement and loss control. The techniques described are proven, practical and effective.

A large part of the new Guide is dedicated to the principles and effects of measurement on the accounts (yield) figures and an understanding of the errors and inaccuracies that may be involved. This should in turn lead to better management of the hydrocarbon inventory. The Guide also discusses the other influences that are important in hydrocarbon management, such as personal motivation and management commitment, and how these may be influenced by internal company factors and by external legislation constraints.

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Meeting the challenge of developing technology

OG21 is an R&D coordination initiative of the Norwegian Ministry of Petroleum and Energy. Here, *Per Gerhard Grini*, General Manger of OG21, together with *Jan Bosio* of Bosio Consulting, outline how the initiative is addressing the challenges of technology development within the Norwegian oil and gas sector.

OG21 was established by the Norwegian Ministry of Petroleum and Energy (MPE) in 2001 as a task force to formulate a national technology strategy for added value and competitive advantage in the Norwegian oil and gas industry. The initiative has received widespread support from the industry as it is expected to boost the creation of new technologies, leading to more concerted and focused efforts in research and technology development.

The national technology strategy proposed by OG21 focuses on:

- Sustained profitability in the Norwegian petroleum industry and resource optimisation on the Norwegian Continental Shelf (NCS).
- Increased technology and knowledge exports by exploiting the competitive advantages and internationalisation of the Norwegian service and supply industry.

There is a general consensus in the Norwegian oil and gas sector that technology development is the single most important factor for reducing costs and enhancing the competitiveness of Norway's oil and gas activities. An increased R&D effort is therefore considered to be extremely important if the gas and oil production from the NCS is to follow the long-term scenario described in the governmental White Paper 38 on oil and gas policy of 2001–2002 (see **Figure 1**).

Technology target areas

During autumn 2002, the MPE appointed 'Lead Parties' (LP) – oil companies acting as operators on the NCS and expert groups – to conduct a detailed evaluation and gap analyses of the technology target areas (TTA) that had been identified during the technology strategy process. These TTAs were considered crucial should the gap between the decline and long-term scenarios be eventually closed. The reports from the TTA expert groups are available on OG21 website at **www.og21.org**

Table 1 shows the nine TTAs, the Lead Parties and the Lead Party representatives.

Achievements and TTA projects

OG21 is one of the major driving forces in petroleum-related R&D in Norway, but does not allocate any funding. Despite this, it has succeeded in setting the premises for a national strategy for technology development.

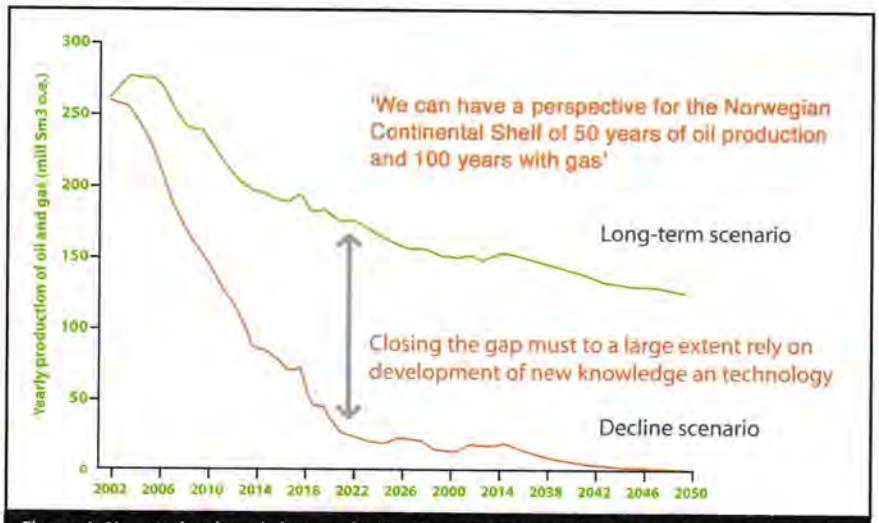

Figure 1: New technology is key to closing the gap between the Norwegian Government's long-term production and decline scenarios for the NCS
Source: Government White Paper 38, 2001–2002

This has been confirmed in the national budget of 2004 where it is stated that governmental funding to petroleum-related R&D shall be allocated to projects which support the objectives of the OG21 technology strategy.

The current funding mechanisms are illustrated in **Figure 2**. The two main contributors are the oil companies and the supplier industry, and government through agencies such as the Research Council of Norway (RCN).

The total funding of petroleum-related R&D in Norway amounted to approximately NKr2,800mn in 2000, as shown in **Table 2**. The oil companies and the supplier industry accounted for approximately 92% of the this figure. Minor changes have occurred since 2000, but the contributions have been of the same order of magnitude from 2000 through 2003.

The OG21 expert groups carried out the gap analyses within each TTA in 2003 and delivered their evaluation reports for a hearing process in the middle of that year. The recommendations prepared by the TTA expert groups were presented at the OG21 Forum in October 2003. The TTA groups were then asked by the OG21 Board to prepare specific project proposals meeting the objectives set forth in the expert group recommendations. Some of these project proposals have been endorsed by the oil and gas industry, others are still under consideration.

Altogether 20 projects proposals were originally presented to the OG21 Board. However some have been withdrawn for technical reasons or because the operators have addressed the project content within their operation routines and maintenance programmes.

The project proposals which are being considered and their current status have been summarised in **Table 3**.

Technology target areas (TTA)	Lead party (representative)
Zero harmful discharge to sea	ConocoPhillips (Ole Lindefjeld)
30% reduced emissions to air	Shell (Helge Skjæveland)
Stimulated recovery	Statoil (Håkon Rueslåtten)
Cost-effective drilling	ExxonMobil (Stu Keller)
Real-time reservoir management	BP (Morten Heir)
Deepwater floating technology	Norsk Hydro (Thore Thuestad)
Long-range wellstream transport	Statoil (Pål Hedne)
Seabed/downhole processing	Total (Oddgeir Johansen)
Competitive gas production and offtake	Shell (Geir Vollsæter)

Table1: OG21 technology target areas, Lead Parties (LP) and Lead Party representatives.

Contributor	Amount (NKr mn)
Oil companies	1,500
Supplier industry	1,100
Government/Agencies	165
Total	**2,800**

Source: OG21 Strategy Document

Table 2: Funding of petroleum-related R&D in Norway

Challenges ahead

Some of the challenges remaining to be addressed by OG21 include:

- Address the need for increased governmental and industrial funding of petroleum R&D.
- Address the need for increased funds for pilot testing of new technology.
- Develop new partnering and risk-sharing models for the development and the implementation of capital-intensive new technology
- Inform the whole petroleum cluster of the needs identified as high priority task in the OG21 technology strategy, in order to create a national converging effort to close the existing technology gaps (see **Figure 1**).
- Focus the fundamental research towards technology needed to reach the long-term scenario outlined in **Figure 1**.

The project proposals submitted to the Management Board of OG21 are, for most part, in the initial phase and several of the oil companies are still considering their degree of involvement.

OG21 has fulfilled its role as a catalyst to the R&D activities within the Norwegian oil and gas sector and will continue to promote the implementation of technology strategy with the industry. It will do this in close cooperation with governmental agencies such as RCN and Demo 2000, the R&D institutes, and academia and professional organisations. These include the Federation of Norwegian Manufacturing Industry (TBL), INTSOK, and the Norwegian Oil Industry Association (OLF). It is envisaged that the strategy document elaborated in 2002 will be updated in 2005.

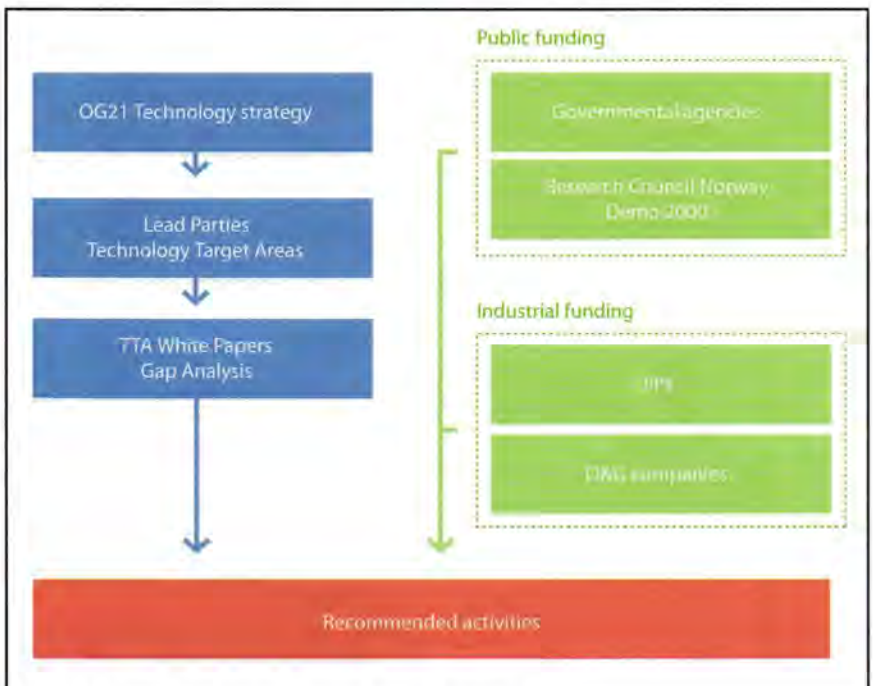

Figure 2: Current funding mechanisms for OG21 projects

TTA	Number of proposals	Project proposals/topics/status
Zero discharge to sea	3	Injection and disposal systems of produced water. Effective monitoring and leak detection systems for pipelines and subsea systems. The project proposals are under revision and are awaiting commitment from the oil companies.
30% reduced emissions to air	3+1	Energy optimisation. NO_X (nitrous oxides) reduction by steam injection technology. Fuel cell and membrane technology. Projects on hold pending back-up work.
Stimulated recovery	2+1	Carbon dioxide (CO_2) injection for improved oil recovery (IOR) and storage (contribution from 'stimulated recovery', 'competitive gas production' and 20% reduced emissions to air): Further work needed on project proposal. WAG/SWAG methods: LP committed to take the lead on the project. Scope and milestones to be agreed upon. Massive depressurisation: Will be handled in one of the operating licences.
Cost-effective drilling	3	Coiled tubing drilling systems. Ultra extended reach wells. Slim well drilling technology. Workshops arranged. LP commitment on one project.
Real-time reservoir management	1	Fibreoptic reservoir data to real time: On-going in one of the operating licences.
Deepwater floating technology	3	Steel catenary riser deep water: Funding almost completed. LP and industry commitment. Lightweight deployment system deep water: Funding application forwarded. LP and industry commitment. Catenary composite riser deep water: LP commitment. Searching for partners.
Long-range wellstream transport.	0	Project proposal process on hold.
Seabed and downhole processing	2	Seabed compressor: Project started. Seabed separation: Awaiting commitment from oil companies.
Competitive gas production and offtake	2+1	New field development solutions for gas: Awaiting oil companies commitment. Flow improvers in high-pressure gas systems for increased transport capacity: Project started.

Table 3: TTA project proposals and status

Energy Management training from the Energy Institute

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The Energy Institute is the professional body for the energy sector and a leading provider of energy management training and education. Energy Institute 1-day Energy Management courses enable energy professionals and newcomers to the industry to keep up-to-date with recent developments in energy management.
These courses provide delegates with practical solutions to assist in producing an effective energy management strategy, increasing energy efficiency and reducing energy consumption.

Our suite of 1-day courses has successfully started for 2004, and we would like to remind you of what is on offer for the rest of 2004:

Introduction to Energy Management – *an introduction to the basic principles including energy policy, investments for energy efficiency, emission targets, climate change levy, energy technology and energy efficiency accreditation.*
The remaining dates are:

- Belfast: 13 May
- Leeds: 17 June
- London: 9 September
- Birmingham: 17 November

Advanced Energy Management – *a suite of five courses – each devote a full day to the following topics:*

- Energy auditing: 22 June, 9 November
- Monitoring and targeting: 11 October
- Energy efficiency in buildings: 15 June, 23 November
- Renewables: 20 May, 4 November
- Educating the workforce: 25 May, 1November

Energy Leader – *a course designed for those who want to gain senior management support for their energy efficiency initiatives and present their case for cost savings and capital investment in the most effective way.*

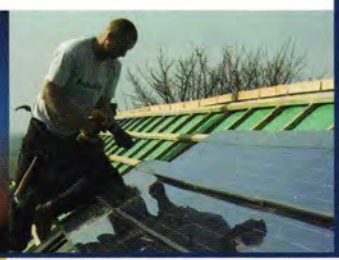
- 20 September

Introduction to Emissions Trading and Verification – *The UK Emissions Trading Scheme has now gone live, and this new course has been designed to Introduce Energy Managers to delivering emission reduction targets, buying and selling emission allowances, Climate Change Agreements (CCAs), surplus trading, Climate Change Levy payments...etc The course will also introduce GHG verification by a third party, which is the condition for participation in trading.*

- 2 December

Waste Minimisation and hidden Energy Waste – *To provide energy managers with the practical framework for identifying hidden energy waste through the application of waste minimisation techniques. The Waste Minimisation approach can directly impact on organisational effectiveness, energy and environmental performance within industry, commerce and the public sector.*

- 15 December



For further information on any of these courses please contact Nellie de la Monneraye at the Energy Institute:

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A centre of attention

ConocoPhillips in Norway has taken remote operations to a new level. It can now operate part of the company's drilling operation from its Onshore Drilling Centre (ODC) located in the main ConocoPhillips' office in Tananger, Norway. The ODC has been a resounding success for the company and has also become a model for other operators who are setting up their own centres, reports *Mike Herbert*, ODC Advisor, ConocoPhillips.

ConocoPhillips's Onshore Drilling Centre (ODC) is located within the company's Tananger office in Norway. The aim was to create the perception of being at the drilling site using existing modern visualisation and communication technology, letting the technology bring people together in a truly integrated team of experts from both ConocoPhillips (onshore and offshore) and its service providers. In particular, the company wanted to close the gap between technological and organisational development – in other words, to get more out of the existing technology.

In order to achieve this goal, it has been necessary to create multi-disciplinary work practices to make a 'step change' in collaboration, communication and integration within ConocoPhillips drilling operations. The company has also had to break down interdisciplinary barriers – both internally, and also externally with its service providers.

This way of working has, in turn, led to a better and quicker decision-making process and improvements in HSE (health, safety and environment). The remote operations facilitated by the ODC have also resulted in a reduction in offshore manning requirements.

Centre layout

When designing the ODC, an important consideration was the inclusion of a 3D visualisation suite and a large 'collaboration room' in the same location as part of a 24/7 operations centre. Modifications to the offshore drilling offices were also required in order to create an environment that would facilitate improved communications and collaboration. Most of the offices have been changed to be more open plan, in order to encourage teamwork – also serving as a videoconference and meeting room when required.

Having a 3D visualisation suite in close proximity to the 24/7 operation room is seen by ConocoPhillips as a key differentiator to other remote operation centres. Indeed, the ODC has now become a model for the development of other centres for operators in Norway.

The technology

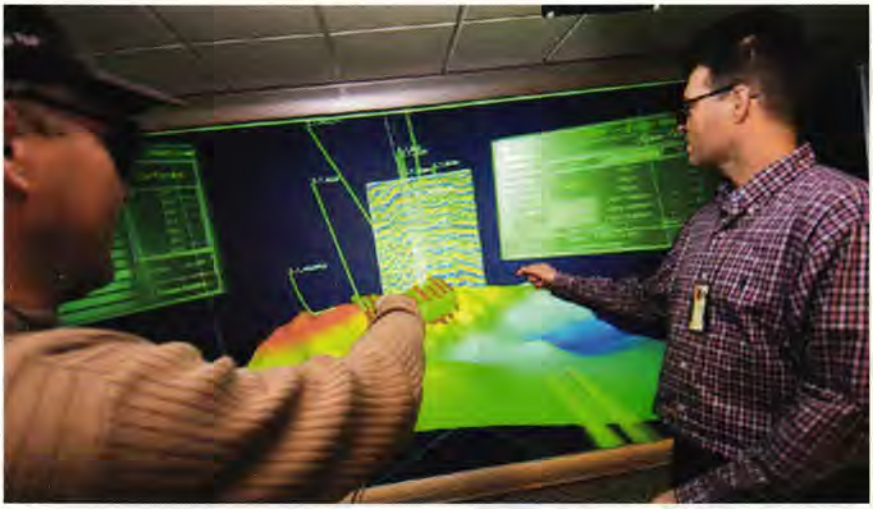
We used current, but high level, communication and visualisation technology to create a 'Virtual Team' consisting of ConocoPhillips' drilling engineers and geologists as well as specialist engineers from our service providers.

A key enabling technology is the fibre cable, which links the ConocoPhillips Tananger office with its drilling and production platforms that lie approximately 300 km away in the North Sea. This high bandwidth connection allows high-quality visual information such as CCTV and video conference, as well as images from a portable and wireless video system to be transmitted in real time to the ODC. Information and data from the drilling equipment and from the sub-surface tools whilst drilling is also sent in real time to the ODC. The ODC team remotely manages several drilling operations by using this visual information, in conjunction with data from sophisticated downhole tools and surface drilling equipment.

Another important communication tool is the UHF link, which allows the onshore engineers in the ODC to talk to any of the offshore team directly.

The engineers who work in the ODC can also remotely control downhole-drilling tools, such as rotary steerable systems, to optimally place the well in the reservoir. Real-time formation information from the measurement-while-drilling tool can also be directly fed into the geological and reservoir models and displayed on large screens in the ODC operations room and, if necessary, on the 3D visualisation screen. This allows the operational geologists to see and visualise all the relevant data sets in order to optimise the well placement as drilling progresses. This is all done in real time, which means decisions are arrived at quicker than with a conventional operation.

The ConocoPhillips' Intranet is also used as a mechanism to distribute much of this information to other team members located outside of the ODC. It also



provides the ODC team with expert internal support from other ConocoPhillips offices. A similar use of the Internet allows global support possibilities. The drilling centre is set up so that it can be securely linked to our contractors' support centres in Norway, as well as in other places around the world. This facilitates further expert support of the operations.

Such an arrangement provides a number of other benefits. For example, it allows ConocoPhillips to take advantage of the time difference between Alaska and Norway (nine hours) to get 24-hour support by specialists during the drilling process. The day shift is covered from the ODC, whilst a smaller centre run by Halliburton in Alaska covers the 'long' night shift.

This type of connectivity is really the backbone of the ODC operations and work processes.

Human factors

The existing, but high-end, technology that is being used can only be successful if the work practices and processes can maximise this technology. ConocoPhillips – together with its main service providers, government agencies and various organisations – made a number changes to existing processes in order to take advantage of the new E-field and Virtual Team that was being created at the ODC.

The focus initially was to move some of the positions from offshore that consisted of mainly PC-based tasks. Typical operations were then used to provide a framework to identify the different people and manning levels required to perform the various tasks required during a drilling operation. A gap analysis was then carried out to identify which tasks would have to be transferred to others who were still located on the offshore platform, when certain positions were moved onshore. Care was taken not to over-load the offshore engineers with too many tasks, so most of the reporting and bureaucratic tasks were also moved onshore.

Changes were also made in order that the offshore schedule was not directly moved onshore. This meant that people working in the ODC would follow an onshore shift schedule, which already existed in the regulations. It was important to ConocoPhillips that no dispensation would be required, which would have been the case if an offshore schedule were used onshore.

There have been many hurdles to clear in this change to accepted work practices – and most have successfully been overcome. Resistance to change and the results of having an ageing work force were just some of the issues that were addressed as part of the process.

The following professions are involved in, or have worked in, the ODC to support operations:

- MWD (measurement while drilling) engineers, data engineers (logging engineers)
- operational geologists
- drilling engineers
- casing JAM operators
- foam cement coordinators
- drilling optimisation engineers
- stimulation engineers
- reservoir engineers
- directional drillers

Some of these positions are manned round the clock (24/7) during certain phases of the drilling operations. Onshore work schedules have been implemented and all people who work in the ODC follow a 3x8 hour shift during weekdays and a 2x12 hour shift at weekends.

Results so far

A number of achievements have been made in the 16 months that the ODC has been in operation, including improvements in HSE performance through the moving of people onshore and reducing their risks. For example, we have seen:

- a reduction in helicopter seats (round trip) – 174
- a reduction in offshore man-days – 1,641
- leading to cost savings in the region of $14mn, while costing the ODC some $4.5mn

The lessons learned to date have shown that the technology is reliable and that the human factors are the key areas to focus on. There have been significant improvements in collaboration and decision-making, which have been indicated by less NPT (non-productive time) and better well placement in the reservoir.

The ability to optimise the use of resources and expertise has been made possible by the connectivity that has been created by the ODC. One specialist engineer is now able to support more than one operation at a time. He can also offer support and assistance to several other operations.

Future developments

In August 2004, the ODC expansion programme will be completed, allowing the centre to support all ConocoPhillips' drilling operations in the North Sea. Work has already begun to create two new operations rooms, which will help support operations such as well service work.

In addition, ConocoPhillips has just started work on constructing an Onshore Operation Centre (OOC), which will initially be used to support and monitor the production process and optimisation, but also maintenance and logistics planning and execution at a later stage.

ODC – key dates

1997	Real-time data and information sent to town and distributed on Intranet
1999	Fibre optic cable installed
2001	ODC planning started in December
2002	Construction work completed November
2003	Eldfisk 2/7-A ODC operations started January
	Ekofisk 2/4-X ODC operations started August
	Eldfisk 2/7-B ODC operations started October
2004	Maersk Gallant ODC operations started

Set for significant reserve and production growth

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

EOG Resources (EOG) is one of the largest independent, non-integrated oil and natural gas companies in the US. It is an S&P 500 Index company and is listed on the New York Stock Exchange. The company's activities are primarily focused in major producing basins in the US, Canada and offshore Trinidad (see **Figure 1a**).

Highlights in 2003

EOG delivered record operating earnings in 2003, posting a net income of $419.1mn, or $3.60 per share, compared with $76.1mn, or $0.65 per share, in 2002. The increase was largely attributed to higher commodity prices. The company also substantially added to its reserve base in 2003, by replacing 249% of production at $1.28/mn cfe finding cost. From drilling alone, EOG replaced 183% of production at a $1.21/mn cfe finding cost. (See **Figure 1b**.)

Natural gas deliveries increased to 955mn cf/d by the close of 2003, up from 924mn cf/d for the comparable period a year earlier. The overall rise in natural gas deliveries was primarily due to a 7% increase in Canadian production to 165mn cf/d, following a major property acquisition, and a 13% increase in Trinidad to 152mn cf/d, attributable to a full year of sales to the CNCL ammonia plant versus only six months of sales in 2002. Meanwhile, natural gas liquids revenues were $11mn higher in 2003 compared to a year earlier, primarily due to a 50% increase in the composite average price and a 3% increase in deliveries.

In addition, 2003 was a year in which several fundamentals were put in place that have set the company for significant reserve and production growth – primarily through the drillbit – through 2004–2006.

EOG also closed the largest property acquisition in its history on 1 October 2003 – acquiring natural gas properties in the Wintering Hills, Drumheller East and Twining areas of southeast Alberta, Canada, from a subsidiary of Husky Energy for approximately $320mn.

In Trinidad, EOG agreed to a 15-year contract to ultimately supply 87mn cf/d of natural gas to the M5000 methanol plant (based on current price and operating assumptions). Now under construction, this new facility is expected to start up in mid-2005 with EOG supplying 95mn cf/d for the first four years.

The company is now also seeking additional reserves through an aggressive drilling programme offshore Trinidad, with the objective of entering new markets that increasingly are aligning with the North American natural gas business. Not only is the region a key supplier of LNG to meet increasing US demand, in addition, ammonia, methanol and chemical production is relocating from North America to Trinidad, driven by attractive natural gas feedstock prices in the island nation.

Another highlight of 2003 was the addition of long-term international production growth with a new project in the southern gas basin of the UK North Sea. First production of approximately 40mn cf/d from two farm-in discoveries is expected to begin in late 2004. EOG is currently reviewing additional farm-in opportunities in this area and expects to participate in several exploration wells in 2004.

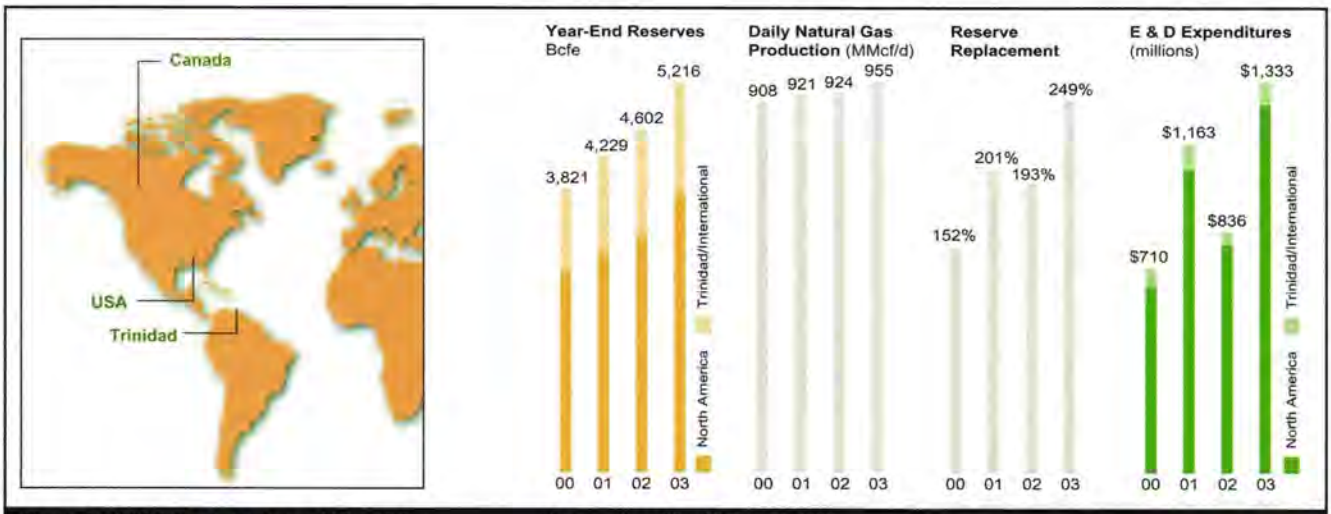


Figure 1: a) EOG Resources' core E&P activity, b) operational highlights in 2003

More recently, in 1Q2004, the Parula #2 and #3 development wells were successfully drilled on the SECC block offshore Trinidad. Combined with the Parula #1 discovery, the three wells are expected to produce some 300mn cf/d of gas. Output from these wells and other sources will be supplying existing gas contracts, including the new ammonia and methanol plants that are scheduled to commence operations in mid-2004 and 2005, respectively.

Trinidadian operations

Construction progressed during 2003 on the N2000 ammonia plant in Trinidad, which is scheduled to start up in 2H2004. EOG will initially supply 60mn cf/d of gas to the project, supplying a total 47mn cf/d net under a 15-year contract.

The company also signed a 15-year contract in early 2004 to supply a portion of the natural gas requirements of the M5000 methanol plant. Currently under construction, start-up of the M5000 facility is planned for mid-2005. When the plant is running at its design capacity, EOG anticipates supplying approximately 95mn cf/d of gas during the first four years and approximately 125mn cf/d during the remaining 11 years of the contract.

The wellhead price will be linked to Caribbean methanol prices, but with a floor price. With this new contract, EOG anticipates another significant increase in its Trinidad production next year. Furthermore, the company believes that there are additional exploration opportunities in its existing acreage position in Trinidad and is continuing to pursue additional acreage.

Outlook for 2004

For 2004, EOG's estimated capital expenditure budget is approximately $1.1bn, excluding acquisitions. The company plans to spend about 5% of this estimated capex budget on drilling new wells and North America will continue to be a key focus area.

EOG also plans make acquisitions that bolster its existing drilling programmes or that offer the company incremental exploration and/or production opportunities.

FPSO and storage tanker on Foinaven field

Pressure testing the leak-sealing clamp

Successful subsea sealing at Foinaven

A recent ROV-installed underwater repair on BP's Foinaven field has proved up the new remote installation approach in the harshest of environments, writes *Chris Skrebowski*.

A leaking sea-bed flanged connection on the Foinaven field has been successfully repaired using Furmanite leak sealing technology, installed by ROV, at a depth of 500 metres. This has enabled the field operator BP to maintain oil production at capacity, by allowing water injection pressure to be maintained.

To affect the repair Furmanite worked with Subsea 7, whose ROV systems were used to install the bespoke Furmanite-designed clamp and to mix and inject the specially-formulated sealing compound – a significant challenge to achieve by remotely operated vehicle.

The 10-inch leaking flange joint was situated on the flowline termination assembly at the base of the Foinaven water injection riser. Seawater ingress at the joint had caused corrosion, which was threatening the output capacity of the field.

Furmanite's clamp solution has been designed to cover the flange connection. 'Space was limited and the clamp had to be operable by ROV, with no opportunity to use heavy lifting gear. So while designed to cover the flange connection, the clamp was also kept to minimum dimensions (666 mm wide, 680 mm high and 140 mm deep, weighing around 200 kg). Furmanite Project Engineer Mike Bowerbank explained that it was also engineered to be compatible with Subsea 7's bespoke ROV deployment system'.

Installation involved lowering the clamp over the pipe, with the lower half suspended by one clamp bolt; the clamp was then rotated until both halves were in-plane with each other, normal to the pipe axis; and (with both bolts now in place) the lower half was drawn up on the bolts, bringing the clamp halves together. With the two halves some 100 mm apart the clamp was moved along the pipe and positioned over the flanges, at which point the bolts were initially tightened to seat and compress the seals, and then fully tensioned to the necessary pre-load to ensure that internal pressure forces would not part the clamp halves.

Key to success

Critical to success was the sealing resin, which was injected once the clamp was in place to seal the gap and bolt clearances. The challenge was to get the resin mix absolutely right to match the leak profile – in other words sufficiently fluid to allow injection and ensure it reached the leak point, while sufficiently viscous to ensure it bridged the 60-mm hole without extruding into the pipeline.

In keeping the clamp as small as possible (covering the flanged connection rather than fully enclosing it), the bolt clearances also had to be considered, as these in effect provided 32 potential leak points that, with full pressure restored, the water would seek to find once the original leak path was sealed. It was therefore crucial that the resin must reach and seal these points too.

A further challenge was to ensure that the resin could be mixed and injected remotely. 'Traditionally for subsea applications the sealing resin would be mixed on the surface, and divers used to install and inject the clamp,' Bowerbank explained. 'Clearly in this instance, with the depths involved, the whole process had to be undertaken by ROV. If the resin were sent down ready-mixed it would have cured before it could be injected, so a special remotely-operated injection and mixing system had to be developed. This involved injecting from separate storage cylinders through a mixer unit to ensure a good homogeneous mix, and then into the clamp.'

Bowerbank added that extensive testing was undertaken to ensure that this crucial element in the repair design would work as required. Two clamps were manufactured so that one could be used for testing purposes, and two test spools were manufactured (at Furmanite's facility in Carlisle), with the appropriate type of 10-inch flanges and a representative defect in the gasket.

The clamp was successfully installed and injected, sealing the leaking joint, in just 24 hours (including injection and cure), ensuring that water injection pressure could be maintained.

A resin for all seasons

A recent breakthrough in resin formulation and its application by FD Alliance (the alliance between Furmanite & DML Composites) means that composites repairs in wet or humid environments are now possible without most of the elaborate preparation previously required.

According to Tony Nicholls, Managing Director of Furmanite, a new resin formulation breakthrough by FD Alliance removes the problems that can be associated with composites repairs in wet or humid environments, and enables repairs to be carried out where not previously possible. He also noted that up to 80% of composites repair projects carried out in outdoor conditions in the UK can benefit from the new resin technology, which opens up a further applications in which permanent composites repairs are possible and viable.

He explained the new approach that was the result of years of research and development by FDA. Previously only water-activated resin systems could be applied in wet conditions, but being hydrophilic they continue to absorb water with a resulting reduction in mechanical properties and are thus only suitable for temporary repairs.

Technical challenge

Paul Hill, Technical Manager of the FD Alliance, explained that the technical challenge was achieving adhesive bonding on a wet surface. Traditionally this meant having to displace water to create adhesion, but this involved such a viscous resin that it was impracticable to use. A low-viscosity resin that still displaces the water has now been achieved – displacing the water chemically rather than physically. According to Hill this means that delays caused by bad weather (typically increasing the final project cost by 30–50%) are eliminated, as are weather protection requirements (costs for tenting and the scaffolders/riggers to erect it).

Similarly, measures to counter condensation (incurring considerable additional costs to carry out the work at night), or to use tenting plus dehumidification/ventilation/heating equipment, are no longer needed.

However, possibly more important is the fact that effective repairs can now be done in areas where previously it would not have been possible – such as splash zones. Hill noted with some pride that the new moisture-tolerant resin system developed by FDA overcomes these problems. Composites repairs can now be applied to repair and strengthen, permanently, in wet weather conditions, splash zones, and where condensation has been an issue. Although he did point out that all FDA composites repairs are waterproof once applied and cured, it's the ability to apply them in wet conditions that now makes the difference.

Hill concluded by noting that in using the new system permanent repairs at pressures up to 100 barg and temperatures to 70°C can be achieved. In addition, extensive testing has been carried out to prove that repairs using the new resin system still satisfy the validation requirements of the Industry Work Group and ASME draft standard specifications.

A repair to a riser on a North Sea production platform

Application of resin composite to achieve a pipe repair

Road tanker management system launched on home market

With over 15,000 installations completed worldwide, Bartec (UK) has now launched its Petrodat 3002 Road Tanker Management System to the home market. DTI-approved for accuracy and ATEX-approved for use with flammable liquids, the new 3002 control unit can memorise up to 5,000 customers and over 30 different products, states the company.

The basic Petrodat installation comprises a 3002 controller, data cartridge reader and printer. Delivery instructions are simply downloaded from a PC in the depot to a data cartridge that is inserted into the driver's cab. At each delivery point, the system records every transaction detail – customer identity, time and date of delivery, product type and volume delivered – and prints a delivery note or invoice. On return to the depot, the data cartridge is removed and downloaded for final invoicing or record keeping purposes in accordance with TDL standard data link or in Excel format. Standard and customised Petrodat software is also available from Bartec to allow for easy integration to existing systems.

The Petrodat 3002 also allows for the addition of an optional additive system that can automatically dispense additives such as detergents, flow improvers and deodorants, etc, in the correct proportions as desired.

Gary Ashburner, Managing Director, Bartec (UK) comments: 'With this system, data can also be transferred automatically by GSM link, which means the tankers need not return to the depot to transfer their information. The new or extra delivery instructions can easily be downloaded via the link, which allows unscheduled or emergency deliveries to take place at greatly reduced costs'. The latest system also includes a GPS system so that the location of the tanker is known at all times, aiding driver navigation and streamlining delivery efficiency.

In addition to this, the Petrodat 3002 system is available in a version for aircraft refuelling, with an integrated interface to airport flight data systems, and a further designated version for depot management systems. These systems can all be supplied with credit card readers to allow customer payment at the tanker.

t: +44 (0)1706 855517
www.bartec.co.uk

Explosion-proof smoke detector

A new beam detector has been designed by Fire Fighting Enterprises to provide protection against smoking fires in large areas with potentially explosive atmospheres. The Fireray Ex detector comprises an infrared transmitter and a receiver, both of which are ATEX-certified for use in hazardous areas, as well as a separate wall-mounted controller to allow adjustment and testing from a convenient non-hazardous location.

The system is designed for large enclosures within oil rigs, refineries, aircraft hangars, ordnance stores and similar premises. It provides an early warning of smouldering or strongly smoke-generative fires, some of which may not be picked up by the flame detectors installed in many hazardous areas, comments the manufacturer.

A modulated infrared beam is sent from the transmitter to the receiver, which generates an alarm if the beam is obscured by smoke. With the two components installed up to 100 metres apart, a single detector set can cover an area of up to 1,500 sq metres. To protect the same area with self-contained 'point' smoke detectors would prove significantly more expensive, claims the company, requiring some 15 special intrinsically safe devices, greatly increasing both hardware and cabling costs.

Fireray Ex also has a drift compensation feature, ensuring that a gradual reduction in signal strength – caused either by the accumulation of dust on the housing or by slight movement of the building – will not result in an unwanted alarm.

t: +44 (0)1438 317216
f: +44 (0)1438 722136

Quick Euromarker test

Tintometer has introduced a low-cost range of visual test equipment for determining the Euromarker (BASF Solvent Yellow 124) mineral oils marking system in marked oils.

The system has been designed for use by customs and excise officials to check on fraudulent use of rebated oils or by oil processors to check marker dosage.

The Euromarker present in the oil is extracted into dilute hydrochloric acid solution and the intensity of the colour produced is proportional to the quantity of Euromarker present in the sample. Using a standard Lovibond comparator, the sample is compared with a series of Lovibond colour glass standards housed in a test disc, which are precalibrated to give direct readings of Euromarker.

Three Lovibond test discs are now available for Euromarker – a roadside test calibrated to determine the percentage of marked oil in unmarked oil over the range 0–10% and two warehouse tests for kerosene or clean diesel that determine the percentage of recommended Euromarker dosage (6 mg Solvent Yellow 124 in 1 litre of oil) present in the marked oil.

www.tintometer.com

Expanded camera inspection system portfolio

EV Offshore's seven new CamScan EVO2 inspection systems are based in Aberdeen and are available for 24/7 call out

EV Offshore's latest subsea camera inspection system – CamScan EVO2 – is reported to be reliable and flexible, and can be used for multiple tasks. A new and improved design is said to greatly reduce service time, allowing greater availability and less down time between jobs. Furthermore, unlike its predecessor, the new design allows for world-class global support as it doesn't have to be serviced in the UK.

To offer engineers the ability to capture visual data while drill pipe is being run, EV Offshore has also teamed up with engineering design company Pilot Drilling Control of Lowestoft, UK, to introduce a new camera running tool. The new drill pipe running tool, with integral flush-through capability, makes it possible to attach the CamScan EVO2 to drill pipe so that, in addition to downhole pressure, temperature and other essential downhole data, engineers can now access conditions visually in real-time. With its black and white low-light camera, and a high definition colour camera, engineers now have access to a quality, high-resolution visual images. Armed with a comprehensive picture of conditions downhole, operations may be carried out with even greater accuracy and confidence, states the company.

Completion, subsea and drilling engineers are also able to act more quickly and confidently because the new system makes it possible to download pictures and short movies from the camera to a memory stick, from which they are transferred on to a PC for emailing to shore.

t: +44 (0)1603 630555
www.evoffshore.com

New manifold saves topside space and weight

A new type of manifold developed by Parker Instrumentation is reported to have helped save weight and space on BHP Billiton Petroleum's Angostura offshore platforms. The design re-engineers the 'monoflange' double-block-and-bleed manifold concept to accommodate two instrument connections instead of one. From a single flange interface to the piping or processing vessel, the new manifold provides connections for both a local visual gauge and an electronic transmitter that connects to the remote control room – each with their own double-block-and-bleed isolation valves.

The new unit integrates all the discrete valves and tube fittings for process pipe to two instruments into a single assembly, reducing the height of the instrumentation by at least 80%, claims Parker. Other benefits include an estimated weight saving of some 70%, a major reduction in the number of connections and potential leak paths, and a significant cost saving.

When connecting to pressurised vessels such as the platform's vapour recovery units, the twin-monoflange design also 'dramatically' reduces the size of the support fabrications that are used to mount the external instrumentation – saving weight and space while greatly reducing the impact of vibration.

With around 50 pairs of instruments on every one of Angostura's three wellhead platforms, the combined savings from installing the new Parker manifold runs to an estimated 4,000 kg, plus hundreds of man-hours of assembly time.

Every manifold also eliminates interface connections, boosting reliability, and saves component costs.

t: +44 (0)1271 313131
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NEW Publications

Insights into Petroleum Geochemistry

Editor: Bernard Colletta (Institut Francais de Petrole Publications/ Editions Technip, 27, rue Ginoux, 75737 Paris Cedex, France. t: +33 (0)1 45 78 33 80; f: +33 (0)1 45 75 37 11; e: **info@editionstechnip.com***). ISBN 2 7108 0843 9. 164 pages. Price: e75/$75.*

Organic geochemistry applied to petroleum exploration has been, for almost fifty years, one of the main fields of research in the Geology-Geochemistry Department of Institut Francais du Petrole (IFP). This book, entirely dedicated to this subject, pays homage to Bernard Tissot and celebrates his admission to the French Academie des Sciences. The contents include one of the founding papers in organic geochemistry written by Tissot, together with a series of new articles that provide an overview of the research in this field. It provides historical insights into the evolution of ideas, summarises the basic technical principles of petroleum geochemistry and gives examples of research activity in geochemistry currently underway at IFP, including its application to basin modelling.

The Cretaceous World*

Editor: Peter Skelton (Cambridge University Press, The Edinburgh Building, Shaftesbury Road, Cambridge CB2 2RU, UK. t: +44 (0)1223 312393; f: +44 (0)1223 315052; **www.cambridge.org***). ISBN 0 521 83112 1. 360 pages. Price (hardback): £75/$110 (also available in paperback, priced £27.95/$50).*

The rich geological record of the Cretaceous Period reveals a world that experienced extreme climatic warmth and significantly higher global sea levels than today. It therefore provides a natural case study of the Earth in 'greenhouse' climatic mode, which this interdisciplinary textbook analyses from the perspective of Earth System Science. The book explores the interactions between the physical, chemical and biological processes occurring both within the Earth and at its surface. These processes control the prevailing environmental conditions on Earth and the book highlights the major differences between the Cretaceous and the present world. Comparison of the global carbon cycle, then and now, is emphasised, although other relevant biogeochemical cycles are also discussed. Finally, the infamous mass extinction that terminated the period, and its possible causes, are investigated.

Petrophysics: Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties*

Djebbar Tiab and Erle C Donaldson (Gulf Professional Publishing/ Elsevier, Linacre House, Jordan Hill, Oxford OX2 8DP, UK. t: +44 (0)1865 474010; f: +44 (0)1865 474011; e: **eurobkinfo@elsevier.com***). ISBN 0 7506 7711 2. 889 pages. Price: £79.99.*

Now in its second edition, this publication offers engineers and geologists a manual for calculations and formulae on fluid flow, rock properties, and many other topics that are encountered every day in locating oil reservoirs. The material has been fully revised and expanded to cover new topics in engineering and geology that have emerged since the first edition was published in 1996. The book reviews the origin, composition and geology of sedimentary rocks and their interstitial fluids and the important role they play in reservoir engineering. Chapters concentrate on the specific theories and mathematics of rock and fluid interactions, and the reader will find complete coverage of electrical, capillary pressure and fluid transport properties. Each chapter has references, problems and solutions at the end for further study or for use in the classroom.

Fuel Effects on Emissions from Modern Gasoline Vehicles, Part 1 – Sulphur Effects.* Part 2 – Aromatics, Olefins and Volatility Effects*

(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***). Part 1: 46 pages; Part 2: 37 pages. Both available as free downloads from* **www.concawe.be**

The influence of gasoline quality on exhaust emissions has been evaluated using four modern European gasoline cars with advanced engine technologies/after-treatment systems designed to reduce fuel consumption and carbon dioxide (CO_2) emissions, including stoichiometric direct injection, lean-burn direct injection and variable valve actuation. Part 1 of this report describes the short-term sensitivity of the four cars to gasoline sulphur content. Part 2 describes the influence of other fuel effects – aromatics, olefins, volatility and final boiling point. All four cars achieved very low emissions levels, in compliance the the appropriate Euro-3 or Euro-4 emssions limits. Part 1 of the report revealed that even at these low emissions levels, all four cars showed very little sensitivity to gasoline sulphur content and that sulphur sensitivity is principally influenced by catalyst system design rather then emissions levels. Part 2 showed that the measured effects of fuel changes on the regulated emissions – NO_x (nitrous oxides), HC (hydrocarbons) and CO (carbon monoxide) – were small and often conflicting, with differing directional responses for different vehicles and emissions. The three direct injection cars emitted higher levels of particulate mass (PM) than the advanced MPI car, although much lower than the Euro-4 diesel PM emission limt. Response to fuel effects was similar in the three direct injection cars. PM emissions from the advanced MPI car, which is more representative of the current fleet, were very low on all fuels tested and insensitive to fuel changes.

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- *Geothermal energy: Utilization and technology.* Mary H Dickson and Mario Fanelli (eds). Renewable Energies, UNESCO, Paris, France, 2003. ISBN 9231039156.
- *Oil crisis & climate challenges: 30 years of energy use in IEA countries.* International Energy Agency (IEA), Paris, France, 2004. ISBN 9264018824.
- *Pipeline risk management manual: Ideas, techniques and resources.* 3rd Edition. K Muhlbauer. Elsevier Gulf Professional Publishing, Oxford, UK, 2004. ISBN 0750675799.
- *The Tanker Register 2004* (includes CD-Rom). 44th Edition. Clarkson Research Studies, London, UK, 2004. ISBN 1903352320.

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Guest Speaker and Presenter
Matthew Pinsent, CBE

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

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

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

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

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

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

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The Energy Institute is pleased to announce

Sir Roy Gardner,

Chief Executive Officer, Centrica

as the recipient of the

70th Melchett Award

22 June 2004, 4 Hamilton Place, London, W1

This free event is a unique opportunity to hear Sir Roy talk about the issues that matter to the energy industry today.

Sir Roy Gardner receives this award for his outstanding contribution to the energy industry. Before joining British Gas, Sir Roy Gardner was Managing Director of GEC Marconi and was appointed to the Board of GEC in 1994. Sir Roy was Chief Operating Officer of Northern Telecom Europe following their take-over of STC, previous to which he was Managing Director of STC Communications Systems and a member of the Board of STC. He joined STC in January 1986 as Finance Director from the Marconi Company where he was Group Finance Director between 1979 and 1985. Sir Roy began his career at the British Aircraft Corporation where he worked in the Commercial Aircraft Division.

On 1 January 2000 Sir Roy was appointed as a Non-Executive Director of Manchester United, and assumed the role of Non-Executive Chairman on 31 March 2002. He was a Non-Executive Director of Laporte plc from December 1996 until the company's takeover in April 2001.

In February 1998 he was appointed President of the Carers National Association, now Carers UK. He is also a Trustee of the Development Trust (for the Mentally Handicapped) and was appointed as Chairman of the Employers' Forum on Disability at the beginning of February 2000. In December 2002, Sir Roy was appointed by the Chancellor, Gordon Brown, as Chairman of the Modern Apprenticeships Task Force and he also Chairs the Ambition: Energy panel.

Sir Roy is a Fellow of the Chartered Association of Certified Accountants, the Royal Aeronautical Society and the Royal Society of Arts. He is also a Member of the Advisory Council of the Prince's Youth Business Trust and a Companion of the Institute of Management.

Programme:

17.45	Registration
18.15	Welcome by Professor Martin Fry, CEng, FEI, Vice President Energy Institute
18.30	Lecture by Sir Roy Gardner
18.50	Questions from the floor
19.20	Drinks reception

Attendance by pre-registration only.

Please return to: Marta Kozlowska, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK t: +44 (0)20 7467 7105 f: +44 (0)20 7580 2230 (one form per person please)

I will attend the meeting 'The Melchett Lecture,' Tuesday 22 June 2004

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For more information about this event please contact:

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