Petroleum review

SEPTEMBER 2004

North Sea

- Development rush as North Sea production declines
- UK/Norway treaty to boost activity

Subsea

- Subsea solutions becoming standard practice

Contractors

- Keeping projects on time and on budget
- Overcoming the innovation barriers

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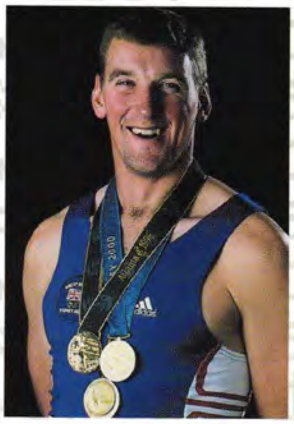
Guest Speaker and Presenter Matthew Pinsent, CBE



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.

As *Petroleum Review* went to press Matthew Pinsent achieved his 4th Olympic gold medal in Athens in a thrilling race which saw the British team beat off a challenge from the Canadians.

And the nominees are... please visit www.eiawards.com

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Energy Institute Registered Charity No. 1097899
61 New Cavendish Street, London W1G 7AR, UK

Petroleum *review*

SEPTEMBER 2004 VOLUME 58 NUMBER 692
SINGLE ISSUE £15.00 · SUBSCRIPTIONS (INLAND) £210.00
(OVERSEAS) £230.00/$330.00 · AIRMAIL £350.00/$490.00

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Printed by Thanet Press Ltd, Margate

US MAIL: *Petroleum Review* (ISSN 0020-3076 USPS 006997) is published monthly by the Energy Institute and is available Periodical Postage Paid at Rahway, New Jersey.

Postmaster: send address changes to *Petroleum Review* c/o Mercury Airfreight International Ltd.

365 Blair Road, Avenel, NJ 07001

ISSN 0020-3076

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

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Front cover picture:
The topsides deck for Clair, the first fixed platform to be installed on the UK's Atlantic Margin, being lowered into place by Saipem's *S7000* heavy lift vessel. See p26 *Photo courtesy of BP*

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The Energy Institute as a body is not responsible either for the statements made or opinions expressed in these pages. Those readers wishing to attend future events advertised are advised to check with the contacts in the organisation listed closer to the date, in case of late changes or cancellations.

ROUNDUP From the Editor

Depletion – the missing demand element?

At the time of writing, West Texas Intermediate (WTI) has just breached \$47/b, with Brent nudging \$44/b. Oil prices are already at all time nominal highs and levels, in real terms, only exceeded in the 1980–1985 period. Cambridge Energy Research's (CERA) recent press release indicated that there was a 50:50 chance of oil prices exceeding \$50/b within 50 days. This now looks to be a racing certainty.

The question that everyone would like answered is: 'Do these prices reflect underlying supply/demand imbalance or have they been driven to these levels by panic and speculation?' If the former, we are in a new world of high oil prices with new capacity and economic slowdown the only brake on the upward momentum. If, however, panic and speculation are key components, then the expectation would be that prices would ease back once a more balanced assessment takes hold. Those that hold the 'panic' view contend that current supplies should be enough to meet demand and rebuild supplies. Some are already questioning why stocks are not already building.

There is an old saying that one should plan for the worst and hope for the best. Companies, at least in private, are good at examining the dire scenarios and checking that they can survive. Governments and international agencies are, however, more reluctant to examine the worst cases. This is largely because they operate more publicly and so are very reluctant to examine extreme or unlikely scenarios for fear of public or market reactions.

In the case of the International Energy Agency (IEA), which is ultimately charged with sharing out available oil supplies (stocks) in the event of a major shortfall, we find that it is publicly reluctant to even mention the impact of depletion. Is this the reason, or part of the reason, that demand has been revised upwards nearly every month this year?

In the July edition of the *Oil Market Report*, the IEA showed how demand growth was met by a combination of non-Opec supply growth and the call on Opec + stock change (see table). However, the missing element is depletion and, as we showed in the August issue of *Petroleum Review*, this is now running at over 1.1mn b/d.

Now growth in oil demand is actually made up of two elements – the increased usage of oil and the amount of outright depletion in various countries that has to be offset by production expansion in other countries. Unfortunately, the IEA does not explain how it deals with depletion. So, if for example, we take the 2003 data, according to the IEA demand growth was 1.6mn b/d, met by 1mn b/d of non-Opec growth and a call on Opec + stock change of 0.6mn b/d.

However, from the re-presented BP statistics (*Petroleum Review* August 2004) we know that depletion was running at 1.1mn b/d and global production grew by 2.7mn b/d. It seems more than a coincidence that when we add 1.1mn b/d of depletion to the IEA's 1.6mn b/d of demand growth we get to the 2.7mn b/d of actual production growth recorded by BP. (There being little significant stock change in the period.)

On the basis of planning for the worst – or rather examining the worst case. we present the table below where depletion as identified in the BP statistics is added to the IEA's demand to get what we have called 'real' demand. We have also done this for the IEA's estimates for 2004 and 2005. Depletion is treated as a positive number as it is effectively additional demand.

While this analysis may not be perfect, it does indicate that depletion can boost demand dramatically. Surely it is time that depletion was treated explicitly rather than being buried in the statistics?

Chris Skrebowski

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

Year	Demand growth[a]	Non-Opec supply growth[a]	Call on Opec + stocks[a]	Depletion[b]	'Real' demand[c]*
2001	0.6	0.9	–0.3	0.5	1.1
2002	0.3	1.7	–1.4	0.4	0.7
2003	1.6	1.0	0.6	1.1	2.7
2004[d]	2.5	1.6	0.9	1.3	3.8
2005[d]	1.8	1.6	0.2	1.5	3.3

The impact of depletion on demand
Sources: [a] *IEA* Oil Market Report, *13 July 2004;* [b] Petroleum Review, *August 2004;* [c] Petroleum Review *calculations;* [d] *estimates*

e-world

Virtually all offshore trips on the UK Continental Shelf are now being monitored by a web tool that for the first time harmonises the way in which oil and gas companies keep track of the movements of their offshore personnel, offering significant safety, efficiency and cost benefits. Fourteen of the largest UK North Sea operators have adopted Vantage POB since its phased introduction last November. New entrants and a wide range of offshore service companies have also since expressed an interest in linking in to the system. An information leaflet can be viewed at **www.stepchangeinsafety.net**

The UK Health and Safety Commission (HSC) has published an online consultative document containing proposals to implement an EC Directive that amends the scope of major accident hazards Directive 96/82/EC (known as the Seveso II Directive). Seveso II aims to prevent, or limit the consequences of, major accidents for people and environment near establishments that hold or use specific dangerous substances. It is implemented in Great Britain through the Control of Major Accident Hazards (COMAH) Regulations. Member states are obliged to implement the Amendment Directive by 1 July 2005. The Consultation Document can be viewed at **www.hse.gov.uk/chemicals/**

Global cooperation to limit the adverse social and environmental impact of motor vehicles, complemented by further technology advances, is needed to fulfil transport's vital role in the development of modern society, states *Mobility 2030: Meeting the Challenges to Sustainability,* a new report from the World Business Council for Sustainable Development (WBCSD). The report was developed by 12 global automotive and energy companies who have worked together over the past four years, under the sponsorship of the WBCSD to assess the sustainability of their products and to envision the future of mobility, with special focus on road transport. The report can be downloaded from **www.wbcsd.org/web/publications/mobility-fuel.pfd**

TOPCALL International has implemented an SMS solution for Opec in Vienna. Selected recipients are provided, on a daily basis, with the current oil price and other important information that is sent directly to their mobile phones. In addition, the Unified Communications expert has installed a fax solution for all those who need more detailed information. For more details, visit **www.topcall.com**

In Brief

UK

The second licensing round on the *Faroese Continental Shelf has been launched, offering acreage to the east and the south of the Islands. Further details are available from* **www.ofs.fo**

Talisman Energy has reported that the *North Tartan field in North Sea block 15/16a has come onstream at a rate of approximately 6,000 b/d.*

The UK Health and Safety Executive's *(HSE) latest* Offshore Safety Statistics Bulletin 2003/2004 *– are available online at* **www.hse.gov.uk/offshore/statistics/stat0304.htm**

Dana has acquired from Amerada Hess *an additional 53% interest in the Barbara gas-condensate field and surrounding area for $7.5mn. Recoverable reserves are around 120bn cf of gas and 4mn barrels of associated liquids.*

Venture Production has reached agreement *with Eni UK to acquire its 11.11% interest in block 48/10a located in the southern North Sea. The block contains the Venture-operated Annabel discovery and also includes a unitised interest in the ConocoPhillips-led Saturn development* *(see p4)**.*

Stratic Energy has entered into a farm-out *agreement with Noble Energy under which Noble will earn a 30% working interest in UK offshore licence P1093, comprising blocks 16/11 and 16/16.*

North America

ConocoPhillips and BP have unveiled *plans for what is claimed to be the largest-ever heavy oil development programme in Alaska, under which oil production from the West Sak oil field on Alaska's North Slope will be increased to 45,000 b/d by 2007.*

A survey of 47 US gas producers indicated *that 2Q2004 domestic gas production fell 3.8% compared to 2Q2003 levels and was down 0.6% from 1Q2004, according to analysts at Raymond James & Associates.*

Shell has commenced production from *its Glider field in Gulf of Mexico Green Canyon block 248. Glider is the first subsea tie-back to the Brutus tension leg platform (TLP). Shell is operator, with a 75% interest in the field; partnered by Newfiled Exploration (25%).*

NEWS Upstream

Red Hawk field onstream on schedule

Kerr-McGee's (50%) Red Hawk field in the deepwater Gulf of Mexico achieved first production on schedule in July using what is claimed to be the world's first cell spar facility. Red Hawk – Kerr-McGee's deepest development to date, located in 5,300 ft of water on Garden Banks 877 – started production from the first of its two subsea wells just 24 months after sanctioning. Devon Energy owns the remaining 50% interest in the field.

Production from the field, with an estimated resource base of approximately 250bn cf of natural gas, was expected to ramp up to a peak of 120mn cf/d in August after the second well was placed on production.

Red Hawk is Kerr-McGee's fifth operated deepwater hub in the Gulf. The cell spar, a floating production facility, is the third generation of spar systems to be pioneered by the company. The innovative technology is reported to further reduce the reserve threshold for economic development of deepwater fields. Measuring 64 ft in diameter and 560 ft in length, the Kerr-McGee *Global Producer IX* facility can be expanded to a production capacity of 300mn cf/d. The design features six tubes surrounding a seventh tube, each measuring 20 ft in diameter and connected by structural steel.

First oil from Broom

The first well on the Broom field in the UK North Sea has come onstream and is producing 16,000 b/d of oil. Two additional pre-drilled production wells and a water injection well are to be completed this year, along with the drilling of a further injection well. Production is expected to plateau at more than 20,000 b/d.

The field is being developed as a subsea tie-back to the Heather platform. Oil reserves are put at 36mn barrels for the first phase of the project. There are further development opportunities in the vicinity and within the Broom field concession area that are currently being evaluated. In addition, the Broom development will assist substantially in extending the Heather field life.

Lundin Petroleum is the operator, with a 55% working interest. Partners are Challenger Minerals (16%) and Palace Exploration (29%).

Kizomba A onstream

ExxonMobil's $3.4bn Kizomba A project offshore West Africa has come onstream. Estimated recoverable reserves are put at 1bn barrels, with an expected production rate of 250,000 b/d. Kizomba A is the first of three world-class production developments on Angola's block 15 that are intended to collectively develop over 2.5bn barrels of oil at a total investment of around $10bn. Kizomba A will develop the Hungo and Chocalho discoveries. The project includes a surface wellhead platform and subsea wells tied back to an FPSO with a storage capacity of 2.2mn barrels.

Earlier this year, construction began on the Kizomba B project, which will develop the Kissanje and Dikanza discoveries. Kizomba A and B incorporate a unique 'design one, build two' approach that captures substantial synergies. First oil from Kizomba B is scheduled for 2006. Planning and design are also underway for the Kizomba C project.

NEWS Upstream

First gas from In Salah project

BP and state-owned Sonatrach have commenced first gas sales from Algeria's In Salah gas project. The project initially entails the development of three proven gas fields at Krechba, Tegentour and Reg, located in the remote Saharan desert of southern Algeria. The gas is transported along a series of infield pipelines to the project's central processing facility at Krechba, and then along a 500-km export pipeline to Sonatrach's gas hub and collection point at Hassi R'Mel. By the end of this year gas deliveries will plateau at 9bn cm/y of gas, increasing Algerian gas exports by about 15%.

First gas is expected from Sonatrach and BP's other joint development project – In Amenas – by early 2006. Together, In Amenas and In Salah will produce a total of 18bn cm/y.

In June 2003, BP announced the sale of 49% of its equity stake in the In Salah gas project (BP 65% and Sonatrach 35%) to Statoil in a $740mn deal that included 50% of BP's stake in the In Amenas project.

Exmouth sub-basin drilling programme

BHP Billiton has completed a four-well drilling programme in its WA-255-P(2) permit in the Exmouth sub-basin off the coast of northwest Western Australia. The campaign was designed to appraise the Stybarrow oil discovery, made in February 2003, and the oil shows encountered at Eskdale in March 2003, as well as test the block's further exploration potential.

Results are understood to indicate that Stybarrow is a medium-sized oil accumulation.

'BHP Billiton believes the Exmouth sub-basin is developing as an important oil province in Australian waters, having yielded a number of small to medium oil discoveries in recent years,' comments Mike Weill, BHP Billiton Petroleum President–Americas/Australia. 'We have now drilled a total of nine wells in WA-255-P(2) in 2003 and to date in 2004, and are continuing to assess the potential of adjacent prospects.' BHP Billiton operates and owns a 50% interest in WA-255-P with 50% held by Woodside Petroleum.

Meanwhile, BHP Billiton is also drilling the nearby Indian-1 exploration well on behalf of the WA-271-P permit joint venturers, Woodside (60%) and Japan's Mitsui (40%). Data from the well will help assess further exploration potential, and drilling and appraisal requirements in WA-255-P(2), BHP Billiton said. In addition, the company has begun a five-well drilling campaign around the Ravensworth and Crosby discoveries in the nearby block WA-12-R, in which it holds an operating stake of 71.43%. Apache Energy (28.57%) recently reported that the latest well, Ravensworth-2, had extended the field to the north.

Green light for Saturn development

ConocoPhillips has received government approval for development of the Saturn unit area in the UK southern North Sea. First gas is expected in 4Q2005, with an initial gross rate of approximately 75mn cf/d. Production is expected to increase to a maximum rate of around 170mn cf/d within a year following start-up.

The Saturn Unit Area lies in blocks 48/10a and 48/10b, 37 km north of the Lincolnshire Offshore Gas Gathering System (LOGGS). Initially, the development will consist of three wells from a normally unattended six-slot wellhead platform, located over the suspended appraisal well in 25 metres of water. A 43-km, 14-inch gas export pipeline will tie the platform back to new reception facilities to be added to LOGGS.

The Saturn development comprises three gas accumulations, with Hyperion and Atlas being the first to be developed. Current estimates of gross proved and probable reserves for Atlas and Hyperion are over 240bn cf. In addition, the nearby Rhea structure, formerly known as 'P1A', is currently undrilled and, although it does not feature in the initial development plan, it represents material upside potential within the Saturn unit area. Further satellite developments which could be tied back to Saturn include Mimas (located in block 48/09a and formerly known as 'Argo') and Tethys (block 49/11b).

ConocoPhillips is the operator and holds a participating interest of 42.9%. Other partners include RWE Dea UK (35.1%), Venture Production (19.6%) and Eni UK (2.4%).

In Brief

***Shell Canada is reported to have** acquired Athabasca oil sands resources from EnCana. Lease 9 is thought to hold some 1bn barrels of recoverable bitumen.*

***Anadarko has begun production from** three wells at the Marco Polo field in Gulf of Mexico Green Canyon block 608. All six wells are scheduled to be online by early 2005, with a peak daily production of 50,000 boe.*

***EnCana is to sell conventional natural** gas assets producing approximately 7,250 boe/d to Calgary-based Paramount Energy for approximately $219mn (C$292mn) before adjustments.*

Russia & Central Asia

***Aker Kvaerner has signed a letter of** intent to perform fabrication, outfitting and testing of seven barges for oil production in the giant Kashagan oil field in the north Caspian Sea, offshore Kazakhstan. The barge hulls will be fabricated at the Aker Tulcea and Braila Yards in Romania.*

***Shell reports that the exploration** activities carried out in the Salym group of oil fields in Western Siberia – including West Salym, Upper Salym and Vadelyp, for which Salym Petroleum Development holds the licences – have yielded successful results. An exploration well drilled to the depth of 2,316 metres into the Bonus structure in Upper Salym field has indicated an estimated 16 metres of oil-bearing sand. Production from Upper Salym has already begun, with commercial oil production to start by end-2005. Commercial production from Vadelyp is expected by end-2006.*

***TNK-BP is reported to have signed a** deal to develop the Uvatskoye oil field at a cost of some $2bn. The field is expected to yield 10mn t/y of oil over 20 years, starting in 2010.*

***Gazprom has 18,480bn cm of proved** and probable gas reserves, according to auditor DeGolyer & MacNaughton.*

Asia-Pacific

***3i, a leading international private** equity and venture capital company, has completed a $15mn growth capital investment in Singapore-based Pearl Energy for an undisclosed minority equity stake.*

In Brief

TGS-Nopec has commenced the acquisition of a new non-exclusive 2D survey in waters of Indonesia's Makassar Strait. The area covered by the survey is likely to be offered in a bid round by the Indonesian Government during 2H2005.

China National Offshore Oil Corporation (CNOOC) is understood to have signed a petroleum exploration contract with Husky Oil China, covering deepwater block 29/26 in the Pearl River Mouth Basin of the Eastern South China Sea.

Cairn Energy is reported to have made an oil discovery with its N-V-1 well in Rajasthan, its ninth discovery in the state in the last two years. In-place reserves are put at 300mn barrels.

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

Unocal reports that the Gehem discovery offshore Indonesia, made in 2003, has provided the opportunity for a joint deepwater development with the nearby Ranggas field using a common host facility.

Unocal reports that bid results for the recently opened Phase 2 development of the West Seno field offshore Indonesia, including offshore installation and tension leg platform fabrication, were 'unacceptably high'. As a result, cost reduction options are now being considered, and the construction period is expected to extend beyond 2005.

The controversial Stuart shale oil plant at Gladstone in central Queensland is to be closed. The project is thought to have cost more than $150mn since being commissioned some 20 years ago.

Total is to acquire a 39.9% interest in Santos' North Bali 1 PSC offshore Indonesia, and has an option to obtain a further 10.1% stake in the block subject to certain conditions being met.

Santos of Australia is reported to have reached an agreement with ConocoPhillips to jointly explore the NT/P61 licence area in the Timor Sea.

The Vietsovpetro Russian-Vietnamese joint venture is reported to have dis-

NEWS Upstream

High oil prices sustain UK revenues

UK oil production fell to 1,711,711 b/d in May, down 9.1% on the year and its lowest level since June 1992, according to the latest (July) Royal Bank of Scotland *Oil and Gas Index*. However, revenues were sustained by the current period of high oil prices. Gas production, at 9,742mn cf/d, dropped on the month, but rose by 0.9% compared to May 2003.

Tony Wood, Senior Economist, said: 'Oil production in May declined because of seasonal factors and through the ongoing decline in UK oil output. However, the industry can take some heart from the number of applications from non-UK operators during the 22nd Offshore Licensing Round in June. High oil prices are maintaining revenues, which will be relatively positive for UK activity levels.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
May 2003	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	12,642	29.84
Jan 2004	2,014,906	12,689	31.12
Feb	1,972,891	11,331	30.89
Mar	2,006,160	11,819	33.72
Apr	1,964,442	12,078	33.36
May	1,771,711	9,742	37.72

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

North Caspian Sea drill programme completes

Eni and state-owned company Kazmunaigas (KMG) have announced the successful completion of the final, contractually-binding exploration well Kairan-1 in the Kazakh sector of the Caspian offshore. The well, drilled to a depth of 3,850 metres, met an oil pay-zone of more than 500 metres. Production tests have indicated a daily flow rate of 4,100 barrels of good quality 44° API oil. Kairan-1 is the last of the six exploration wells programmed by the North Caspian Sea PSA, of which Eni is sole operator through Agip KCO. The wells were all successful and have led to the discovery of the Kashagan field (the largest reservoir discovered in the last 30 years), Kashagan South West, Kalamkas, Aktote and, finally, Kairan. Additional studies are currently underway to appraise the discovery in more depth.

Partners in the North Caspian Sea PSA are Eni (operator, 16.67%), ExxonMobil (16.67%), Shell (16.67%), BG (16.67%), Total (16.67%), Inpex (8.33%) and ConocoPhillips (8.33%).

Permission sought for Barents well

Statoil has submitted an application to the Norwegian Pollution Control Authority (SFT) for an emission permit to drill on the Uranus prospect in the Barents Sea. The exploration well will be second in what is reported to be the most environment-friendly drilling campaign ever conducted on the Norwegian Continental Shelf. Statoil's request for a permit is accompanied by an environmental risk analysis and emergency response plan for the operation.

The application is based on the principles enshrined in the recent impact assessment for offshore operations in the northern Norwegian Sea and the Barents Sea. These require the well to be planned with no discharges to the sea except with the hole section for surface casing – in other words, the topmost 400 metres. Discharges in the latter case will consist largely of natural substances such as salt and clay. But it will be necessary to emit about 2 kg of pipe dope, a small portion of which is characterised as environmentally harmful. Since the amount is so small, this is considered acceptable. The well will utilise water-based mud, and drill cuttings are to be shipped to land.

Shell R&D deal for Smart Field tech

Shell has signed a series of research and development partnerships with leading technology companies to accelerate the development and deployment of next generation digital oil and gas field technology – referred to by Shell as the Smart Fields™ programme.

The Smart Fields programme integrates real-time measurement, monitoring and control technologies for oil and gas field operations and development planning. Turning the concept into reality will depend on developing and deploying novel technologies from a variety of sources. John Darley, Technology Director of Shell Exploration and Production, said: 'Smart Fields will focus on technology integration to optimise hydrocarbon production and recovery. These partnerships represent a significant milestone for our Smart Fields programme. Our aim is to import and adapt innovative technologies to complement our internal developments and established solutions. To realise full value, we will need to be successful in combining technical contributions into an integrated capability, while still ensuring a level playing field for involvement of other technology suppliers.'

Pieter Kapteijn, Manager of Shell's Smart Fields Programme, added: 'The EP industry is starting to appreciate that "digital oil field" concepts can add significant value. The drive to develop integrated measurement, modelling and control technologies is gathering momentum. Shell established Smart Fields in 2002 to acquire and implement these technologies within key E&P processes such as field development planning, reservoir management and production optimisation.'

The companies with which Shell has signed partnerships are Schlumberger Information Solutions (SIS), Invensys, IBM, Intelligent Agent Corporation (IAC), Science Applications International Corporation (SAIC) and Microsoft. Shell is expecting to start piloting an initial set of solutions in the near future. The partners are expected to release parts of the solutions as commercial products as early as 2005.

Schlumberger Information Solutions provides the expertise to develop collaborative, IT-enabled solutions that improve field development processes. Invensys' contributions are adaptive collaboration and integration technologies for production management and optimisation processes. Intelligent Agent Corporation (IAC) and IBM's Research organisation are contributing complementary technologies to automate and enhance production system monitoring and diagnostics and to provide intelligent event prediction. SAIC's role will bring systems integration and program management support as well as technology expertise from other sectors, and Microsoft brings its expertise and product developments in the area of web based connectivity and Services Oriented Architecture (SOA).

Green light for Northern Block G development

Amerada Hess reports that its plan of development for the Northern Block G area (85%, operator) has been approved by the Government of Equatorial Guinea. The integrated development plan for the Okume, Oveng, Ebano and Elon reservoirs calls for a combination of two tension leg platforms (TLPs) set in 900 ft and 1,750 ft of water, four fixed platforms set in 150–230 ft of water and the drilling of 29 production wells. The plan also provides for 16 water injection wells and two gas injection wells to maintain reservoir pressure and enhance oil recovery.

Production from the fields will be gathered at a central processing facility (CPF) located at the shallow water Elon field. A 24-km subsea pipeline will connect the CPF to the *Sendje Ceiba* FPSO for storage and offloading of crude production. The *Sendje Ceiba*, which has a crude storage capacity of 2.1mn barrels, currently processes, stores and offloads crude production from the nearby Ceiba field.

First oil is expected by 1Q2007, at a rate of approximately 60,000 b/d. Field partners are Energy Africa (15%) and national oil company GEPetrol (5%).

First oil from China's Bohai Bay block

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

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

***Australia is reported to have refused** an offer by East Timor to have New Zealand resolve a dispute over the Sunrise gas field by mediating negotiations over maritime boundaries in the Timor Sea.*

Latin America

***Statoil has secured operatorships for** four deepwater blocks and interests in two other licences on the Brazilian Continental Shelf in the country's sixth licensing round.*

***Unocal has sold its 50% interest in a** jointly held project company that owns UnoPaso Exploração e Produção de Petróleo e Gás, a Brazilian E&P venture, for $61mn plus approximately $7mn in working capital. The purchaser is El Paso Production International Cayman, a subsidiary of El Paso Corporation, which now owns 100% of UnoPaso.*

Africa

***BP has made a new gas discovery in** the Western Nile Delta with it Polaris 1 exploration well in the West Mediterranean Deep Water (WMDW) concession. The well flowed gas at a rate of 26.5mn cf/d.*

***Statoil has been awarded operator**ship for the Hassi Mouina gas block in Algeria, taking a 75% share. Algerian Sonatrach holds the remaining 25% stake in the block, which lies in the Timimoun Basin. Hassi Mouina lies near the In Salah gas project, where Statoil has a 31.85% interest.*

***Burren Energy (35%) has discovered oil** in the M'Boundi field development in the Kouilou PSA in Congo Brazzaville. The MB701 well flowed at 4,000 b/d and is to be put into production.*

***Dana Petroleum has secured a farm-in** partner for its frontier block 8 acreage in the deepwaters off Mauritania. Wintershall of Germany has agreed to pay all of Dana's costs through to the end of the first exploration period in return for a 38.5% stake.*

In Brief

NEWS Industry

UK

***Shell has reported a 2Q2004 net** income of $4bn, an increase of 54% on the same period last year. BP's second quarter pro forma result was $3,908mn, compared with $3,165mn a year ago, an increase of 23%.*

***Eni has unveiled plans to consolidate** its UK based E&P and oil and gas trading activities in London, leading to some 60 redundancies.*

***UK Energy Minister Stephen Timms has** set out plans for the promised review of the Renewables Obligation (RO), due to start later this year, at* **www.dti.gov.uk/energy/renewables/policy/terms_of_reference.shtml**

Europe

***Fluor Corporation has been awarded a** NKr400mn export capacity upgrading contract at the Kollsnes gas terminal by Statoil. The project will increase gas export capacity by 20% to 143mn cm/d and is due onstream in August 2006.*

***The first-ever direct export of natural** gas from Denmark to the Netherlands took place through a new 100-km subsea pipeline in late July.*

***Foster Wheeler has been awarded a** contract for an LNG terminal expansion in Cartagena, Spain, by Enagas.*

***Saipem, in consortium with the** Belgian companies CFE and FONTEC, has been awarded by Fluxys the lump sum turnkey contract to expand the Zeebrugge LNG receiving terminal's capacity from 4.5bn cmly to 9bn cmly of natural gas.*

North America

***Canadian-based Irving Oil is reported** to have been given the green light for its LNG receiving terminal in New Brunswick on the US East Coast.*

***ExxonMobil has reported a 2Q2004 net** income of $5,790mn, an increase of 39% from 2Q2003, while ConocoPhillips reported a quarterly net income of $2,075mn (2Q2003: $1,187mn). ChevronTexaco posted a record 2Q2004 net income of $4.1bn (2Q2003: $1.6bn) and Unocal reported record preliminary net earnings of $341mn for the period (2Q2003: $177mn). Marathon Oil*

Bolivian gas exports a step closer?

President Carlos Mesa is reported to have obtained crucial support in a referendum for plans to increase state involvement in the country's natural gas industry and allow gas exports. The initial returns from under 2% of precincts are understood to have indicated a victory vote for Mesa, who had staked his political future on the referendum affecting Bolivia's gas market, the second-largest in Latin America. A 'yes' vote will allow foreign companies to continue exploiting natural gas, while a section of the industry would be nationalised. Voters are also reported to have supported plans to re-nationalise the former state utility Yacimientos Petroliferos Fiscales Bolivianos, which was privatised in 1997.

The referendum also included a question on using gas as a negotiating tool with Chile to buy back at least part of Bolivia's outlet to the sea. Bolivia has had tense relations with Chile since it lost access to the Pacific Ocean during an 1879–1883 war. It was Bolivian nationalist opposition to building a pipeline to a Chilean port that led to former President Gonzalo Sanchez de Lozada's downfall. He resigned in October 2003 following strikes and violent protests over his plan to spend $5bn to build a gas pipeline through neighboring Chile. Some 80 people died in the unrest.

Bolivia has some 150bn cm of gas reserves. Gas revenues are needed to pay down the country's $5bn foreign debt and to ease the plight of at least some of the 80% of its population that lives in poverty.

Recent European Union developments

The European Environment Agency (EEA) says the old 15-member European Union's (EU) greenhouse gas emissions fell by 0.5% from 2001–2002, following increases in the previous two years. Sadly, proactive anti-global warming measures were not top of the agency's reasons for the cut, writes *Keith Nuthall.* These included warmer weather – reducing heating emissions – and economic problems in some manufacturing industries. The full report is available online from **www.reports.eea.eu.int/technical_report_2004_2/en** The survey comes as the European Investment Bank (EIB) considers lending Italian utility ASM Brescia some 200mn to convert an oil-fired power plant in Ponti sul Mincio to combined cycle gas in order to cut emissions.

In other EU news:

- The EIB is considering lending DKr500mn to Denmark's DONG and a consortium of AP Møller-Mærsk, Shell and Texaco for building a 100-km natural gas transmission pipeline from the country's North Sea Tyra gas field. It would link with the NOGAT pipeline off the Netherlands.
- The European Bank for Reconstruction and Development (EBRD) has plans to invest up to $73mn in the Romania's state oil and gas company to improve corporate governance during its privatisation Meanwhile, the EBRD is part-financing with $81.6mn a 448-km oil pipeline connecting oil fields in central Kazakhstan to Europe-bound export pipelines..
- The new Dutch EU Presidency wants to strike this year a draft agreement with Russia on European gas supplies.
- EU Energy Commissioner Loyola de Palacio has announced EU assistance to help reform Turkey's natural gas sector, including gas transmission and transit, given Turkey's key position a gas hub for north African and Central Asian gas.
- Spain has been pressed by the European Commission to implement a European Court of Justice (ECJ) ruling of last May, telling it to liberalise a law giving the Spanish Government the right to block deals involving privatised oil company Repsol.
- The Commission has asked Greece to stop preventing individual service stations directly importing fuel and oil instead of using a trader holding a marketing licence.
- The Dutch Government is being taken to the ECJ by the Commission over failing to implement EU legislation insisting on low-sulphur fuel. Meanwhile, Britain has been censured by the ECJ for failing to promote the regeneration of waste oils.
- Italy has been told it should scrap a special environmental tax on Algerian natural gas piped to or across Italy to other EU member countries. Brussels says the tax is discriminatory.
- The EBRD could lend $12mn to the Isle of Man's Silverburn Shipping Company to part-finance 24 tugs and barges for Caspian oil fields.
- The Commission is preparing to launch a €250,000 study into hydrogen and fuel cell technologies that could be widely marketed within 15 years.

ConocoPhillips signs Indonesian gas deal

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

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

ConocoPhillips is the operator of the Corridor Block PSC with a 54% interest. Other partners are Talisman (36%) and Pertamina (10%).

Russian Government increases oil taxes

Russian oil taxes increased at the beginning of August. Export duties are calculated on the basis of the average Urals price in the North-West European and Mediterranean markets over the two months preceding the month for which they are charged. The new formula is:

- **If crude is below $15/b, export duty will be 0%**
- **If crude is $15–$20/b, export duty will be (Urals price – $15) x 35%**
- **If crude is $20–$25/b, export duty will be $1.75 + (Urals price – $20) x 45%**
- **If crude is above $25/b, export duty will be $4 + (Urals price – $25) x 65%**

According to UFG, at present, some 65 cents in ever dollar is taken by the Russian Government in export duty, compared to the previous system that took 40 cents whatever the price.

Meanwhile, Russian Minister of Economic Development and Trade, German Gref, is reported to have proposed that mineral extraction taxes for oil and gas companies be increased – the base rate for crude from Rb400/t to Rb419 and the rate for gas from Rb107/mn cm to Rb135. He is also understood to have proposed raising domestic gas tariffs by 23% (instead of 20%) from 2005.

Train Six for Bonny

Project consent has been given for the construction of the natural gas liquefaction unit at Nigeria's Bonny plant in the Niger River delta. The project is being developed by Nigeria LNG, a joint venture of NNPC (Nigerian National Petroleum Corporation; 49%), Shell (25.6%), Total (15%) and Eni (10.4%).

The sixth unit will go into production at the end of 2007 and will have a capacity of 4.1mn t/y of LNG and 1mn t/y of condensates and LPG.

Following commissioning of the new plant, Nigeria LNG will have a production capacity of 22mn t/y of LNG, making it one of the leading producers of LNG in the world.

Shell is to purchase 3mn t/y of LNG from Train Six to supply customers in North America and Europe.

Petronas gas to UK

Petronas has signed a gas sales agreement with British Gas Trading, a subsidiary of Centrica, to supply up to 3bn cm/y of natural gas for 15 years, beginning 2007. The deal marks a major breakthrough for Petronas in its quest to enter the UK natural gas market and at the same time will enhance its overall position in the global LNG business.

Under the agreement, Petronas will supply the gas to Centrica via the LNG receiving terminal being developed by Dragon LNG at Milford Haven, Wales. Petronas has 30% equity in Dragon LNG, while BG Group and Petroplus have 50% and 20% stakes respectively. The terminal will be able to process up to 6bn cm/y of gas and is scheduled to start operation by 2007.

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reported a 2Q2004 net income of $352mn (2Q003: $248mn; Amerada Hess $288mn ($252mn); Anadarko $405mn ($301mn); Apache $372mn ($243mn); and Petro-Canada $484mn ($355mn).

***Galveston LNG is reportedly proposing** to build an 8.5mn cm/d LNG receiving terminal at Ridley Island, a former coal terminal on the Canadian west coast. Meanwhile, WestPac Terminals has unveiled plans for a 10mn cm/d facility at Kitimat, also on the Canadian west coast.*

Middle East

***Calgary-based Husky Energy has** acquired Temple Exploration for $115mn.*

***Iran and Iraq are reported to have** revived plans to build a crude oil export pipeline that would transport from 350,000 b/d of Basra Light to Iran's Abadan oil refinery.*

Russia & Central Asia

***Yukos is reported to have sold a 56%** stake in Siberian natural gas company Rospanto TNK-BP for $357mn.*

***The Ukrainian pipeline monopoly** Ukrtransnafta and TNK-BP are reported to have signed an agreement that effectively sanctions a reversal of the Odessa-Brody pipeline.*

***Transneft is understood to have** increased the capacity of the Baltic Pipeline System from 840,000 b/d to 950,000 b/d. This is to be further increased to 1mn b/d by the end of 2004, and 1.24mn b/d from 2006.*

***The Russian Government is to sell the** state's remaining 7.59% stake in Lukoil.*

***Lukoil-Kaliningradmorneft has started** commercial production at the Kravtsovskoye (D-6) field in the Baltic offshore.*

Asia-Pacific

***PetroChina is reported to have issued a** letter to end a joint venture under which a foreign consortium comprising Gazprom, Shell and ExxonMobil was to invest in the $5.2bn, 12bn cm/y, 4,000-km West-East pipline linking fields in China's northwest Xinjiang Province with Shanghai. The consortium partners were unable to agree the financial terms of their participation.*

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UK

***BP and Shell have joined 10 key** players in the automobile and electricity industries in releasing a long-term strategy for the promotion of sustainable energy, writes* Keith Nuthall. Mobility 2030: Meeting the Challenges to Sustainability *includes commitments on reducing emissions and energy consumption. It says 2030 is the earliest that transport emissions could cease being the largest greenhouse gas source.*

***HydroWingas, the Norwegian-German** joint venture, has acquired its first UK customer – supplying gas to Devro, a leading manufacturer of collagen products for the food industry.*

Europe

***Octel has strengthened its position in** the market for the manufacture and supply of fuel additives and speciality chemicals by acquiring German chemical product manufacturer Leuna Polymer for an undisclosed sum.*

***GE Energy has announced that it has** been awarded one of the first contracts in the European Union (EU) to help meet the lowered nitrous oxides (NO_X) emission limits for power stations recently set by the EU Large Combustion Plant Directive for 2008 and 2015. The contract was awarded by EDF Energy for its West Burton power station in north Nottinghamshire, UK. Under the contract, GE will deliver a turnkey NO_X reduction solution custom designed for the facility. GE reports that its NO_X control solution will achieve 400 mg/cm NO_X levels with a broad range of coals, 100mg/cm lower than the 2008 limit.*

Eastern Europe

***Mol is reportedly planning to only sell** a 75% stake in its natural gas subsidiaries – storage firm Mol Foldgaztarolo, trading arm Mol Foldgazellato, and gas shipment and system operator Mol Foldgazszallito – retaining the remaining 25%. Mol plans to use proceeds to increase its stake in Croatia's INA, build a greenfield service station network in Serbia, or develop its retail network in Slovakia, among other goals.*

***OMV has acquired a 51% stake in** Petrom through the direct purchase of*

NEWS Downstream

Call to 'get tough' on UK utilities

New independent research commissioned by WWF shows the UK power sector could do nine times more to reduce its carbon dioxide (CO_2) emissions, thereby significantly reducing the UK's contribution to climate change. Matthew Davis, Director of WWF's PowerSwitch climate change campaign, said: 'WWF is calling on the power sector, the biggest CO_2 polluters in the UK, to reduce their CO_2 emissions. However, the government is bowing to pressure from the power sector rather than getting tough. This new research clearly shows the industry could be slashing its emissions at a relatively low cost.'

At present, the UK power sector is lobbying government to further weaken CO_2 targets set for it under the UK's National Allocation Plan. It argues that the planned CO_2 reductions could damage competition in the UK energy industry. However, leading energy consultant ILEX, who carried out the research, calculated that the UK power sector could reduce its CO_2 emissions by much more than presently asked under the current EU Emissions Trading Scheme.

The government's UK National Allocation Plan for 2005–2007 estimates the CO_2 savings potential for high-energy use sectors, including the power sector, to be 5.5mn tonnes. However, the projections by ILEX show there is potential for much larger cuts within the UK power sector alone – showing CO_2 emissions savings potential of 48.2mn tonnes over the same time period.

WWF believes that stricter limits, with fewer CO_2 emissions allowances and hence a higher carbon price, across Europe is critically required, especially if the UK is to maintain leadership on climate change issues and is to meet its domestic targets for CO_2 reductions. It argues that a high carbon price will penalise the UK's inefficient coal-fired power stations for their high CO_2 emissions and instead will duly promote investment in cleaner forms of electricity generation such as gas and renewables.

Andrea Kaszewski, Climate Change Policy Officer, said: 'Claims made by industry that UK electricity generators would lose out to European competition if tighter CO_2 targets were put in place are very unlikely as they only face internal competition in the UK. Furthermore, the UK can continue to have an economic and successful power sector, but with much reduced carbon dioxide emissions, if the government were to get tough on the power companies and force them to deliver the potential savings.'

A cleaner future for road haulage

A new co-operative venture has been formed to contribute to a cleaner future in the road haulage sector, as the vast majority of western European heavy truck manufacturers have decided in favour of emission control using SCR (selective catalytic reduction) technology to meet the new Euro 4 and Euro 5 exhaust emission standards. DAF, Iveco, Mercedes-Benz, Renault Trucks and Volvo Trucks together represent some 80% of the European truck market.

SCR reduces harmful nitrogen oxides (NO_X) into harmless nitrogen and water by means of a catalytic converter with the help of metered quantities of AdBlue sprayed into the hot exhaust gas stream. AdBlue is the commercial name given to a high quality, standardised and synthetically produced aqueous urea solution. Trucks and heavy commercial vehicles with SCR technology attain the Euro 4 exhaust gas emission standards prescribed from 2006, and will – in an improved version – also be able to meet the next stage, Euro 5, which comes into effect from 2009. In addition, a truck equipped with SCR is expected to have 2%–5% lower fuel consumption than a comparable Euro 3 vehicle.

Meanwhile, supplies of the DIN 70070 AdBlue are now assured by leading European urea producers such as AMI Agrolinz Melamin International, BASF, Fertiberia, Grande Paroisse, SKW Stickstoffwerke Piesteritz and Yara International, who, together with their distribution partners, are currently establishing a Europe-wide network to supply their customers.

Several European countries are already encouraging advance compliance with Euro 4 and Euro 5 via incentives such as lower road tolls (eg 10 instead of 12 cents/km in Germany) or more favourable depreciation rates for correspondingly equipped vehicles (eg in the Netherlands). Incentives to use this environmentally friendly technology are shortly to be expected in other European countries. According to present findings, the operating costs of long-distance trucks with SCR technology will not increase compared to the current Euro 3 emission standard, despite considerably reduced emission values. Other advantages of SCR include very good operating reliability and a long range given a correspondingly large AdBlue tank capacity.

NEWS Downstream

Largest ever survey of UK forecourt shop sector

The UK forecourt shop sector has long been difficult to track from a supplier and retailer perspective. Too many suppliers see the market as highly fragmented and concentrate efforts on the disciplined oil company-owned sites. By contrast with the standalone convenience store (C-store) sector, where multiple retailers are buying up small store chains in a feeding frenzy of acquisition, in the forecourt shop sector it is the dealer-operated sites – forecourt multiples like Fuelforce and brands such as Spar – who are the more aggressive.

In this environment of change and opportunity, grocery research company Insight Research has teamed up with data expert Catalist to conduct the largest ever survey of UK forecourt shops, to provide both retailers and suppliers with an effective sales development tool. Insight interviewed 700 UK forecourt shops, accounting for almost 8% of the total UK market, in a detailed quantitative and qualitative research programme supported by a group of key suppliers. The research challenges many existing assumptions about the market and is likely to lead to new strategic initiatives by many suppliers.

Petrol creates footfall in forecourt shops, while profits are mainly derived from shop sales. Site operators estimate that more than half of their customers buy from the shop, with an average basket size of £5.70. Motorists are highly sensitive to fuel prices; by contrast, forecourts are able to extract excellent margins from shop sales, much of which is paid for by card.

Further details are available from Dan Munford at Insight Research. He can be contacted on t: +44 (0)1938 556 090, e: **dan@insightresearch.co.uk** The company website is **www.insightresearch.co.uk**

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.*

Clean coal cheaper than gas

Contrary to the commonly held belief that it is too expensive or impossible to clean up coal-fired electricity generators to the point where they are comparable to gas turbines, the facts and prospects justify the opposite conclusion, according to Northfied, Illinois-based McIlvaine Company. 'The biggest argument used against coal plants is that they emit more greenhouse gases. Future gas supplies will be LNG, which adds a 30% greenhouse gas addition. This is due to the energy required to liquefy, transport, and then vapourise the gas. When one also takes into account methane emissions in pipelines, a new super critical coal plant will be at least comparable.'

'The net greenhouse gases from a coal plant will even be less if the plant co-fires biomass. This is one of the best ways to foster the use of renewable energy. A variation on this concept is biomass gasification and introduction of that gas for coal reburn. This process reduces fuel costs, decreases NO_x (nitrous oxides) and increases electricity output.'

'Emissions of particulates, SO_2 (sulphur oxides), NO_x, mercury and metal toxics can be reduced to very low levels. Permits for a number of new coal plants substantiate this level of performance. One big potential is the creation of hydrochloric acid as a byproduct. This could boost mercury reductions well above 90%'.

McIlvaine also states that: 'The biggest area of controversy has been applying these control technologies to existing plants. Site specific factors make it expensive to add new controls. But total emission reduction to low levels can be achieved at less than 1 cent/kWh increase in cost. The stumbling block to date is lack of a practical plan for achieving reductions of particulate, mercury and metal toxics. Regulators and involved parties have become confused as to the difference between routes, speed, and destination. Cap and trade has been proposed as a route and speed determinator when, in fact, it is only useful as a destination (cap) and a way to operate once the destination is reached (trade).'

The McIlvaine Company has drafted and submitted to EPA a plan that it claims provides a much better route and controls the speed at a rate which both environmentalists and utilities would find acceptable. It involves yearly escalating payments by the higher emitting utilities to the lower emitting utilities. This results in reaching the destination with the optimum route and speed. The complete plan can be viewed online at **www.mcilvainecompany.com/comments_to_neshap_for_utilities.htm**

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33.34% and a simultaneous capital increase in Petrom. The deal adds some 1bn boe of oil and gas reserves, more than tripling OMV's reserves portfolio. The Petrom acquisition also boosts OMV's share in the Romanian refining and marketing market to 18%.

***Shell Global Solutions is understood to** have signed a licensing deal with Poland's second largest fuel refiner, Lotos, for an integrated gasification combined cycle (IGCC) project to boost oil processing volume and offer higher-value products.*

Russia & Central Asia

***UES subsidiary Inter RAO is understood** to have submitted a bid for a 66% stake in the Slovakian national power utility Slovenske Elektrarne. Inter RAO is representing a consortium comprising itself, German energy trader OstElektra, Norsk Hydro, E.On Ruhrgas and Framatom, a French producer of nuclear power generation equipment.*

Asia-Pacific

***Foster Wheeler and OGP Technical** Services have been awarded a project management consultancy (PMC) contract by Petronas for the addition of a lube baseoil plant at its refinery at Melaka, Malaysia.*

***The NWS Venture LNG Sellers have** signed an agreement with the Kansai Electric Power Company for the supply and purchase of 0.5mn t/y of LNG between 2009 and 2014, and 0.925mn t/y of LNG between 2015 and 2023. Kansai Electric is Japan's second largest power company, providing electricity to 13mn customers in Japan's Kansai region.*

***Aker Kvaerner has been awarded a** contract by BP for the delivery of a new facility for the production of clean gasoline at the Bulwer Island refinery in Queensland, Australia. The facility is due to be commissioned by 1 January 2005.*

***Foster Wheeler has been awarded a** project management consultancy contract by Hyundai Oilbank (HDO) for a $200mn clean fuels upgrade project at the HDO refinery at Daesan, Korea. The project will reduce the sulphur content of the motor gasoline (mogas) hydrodesulfurisation unit from 200 ppm to 30 ppm and the gas oil from the new gas oil hydrotreating unit to*

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10 ppm, in order to comply with the Korean Government's new environmental legislation that comes into effect on 1 January 2006.

***BP and Petrolub International have** reached an agreement to merge their automotive lubricant businesses in Japan to create a new company called BP Castrol KK with combined total sales revenues of $180mn (Y20bn). Following the transaction, BP will own around 70% of BP Castrol KK.*

Latin America

***The Argentinean energy crisis recently** forced local companies to significantly cut their supply of natural gas to Chile, which is 90% dependent on such supplies to meet some 37% of its electricity needs. As a result, Chile's main thermal energy producer, AES Gener, together with Santiago Electricity, are reported to have gone before the International Arbitrage Court to demand that the Argentine companies deliver all the supply contracted and pay compensation for the losses generated by the cuts. Argentina, however, argues that its laws state that domestic demand in an energy crisis has priority over exports.*

Africa

***Tanzania is reported to have begun** producing 115 MW of electricity at the Ubungo power station at Dar es Salaam, as part of a $260mn gas-to-electricity project involving a 225-km gas pipeline from Songo Songo Island in southern Tanzania.*

NEWS Downstream

Open season for Keystone gas storage

Unocal has announced that its Keystone facility in West Texas is conducting a non-binding open season for future natural gas storage capacity that will continue through September 2004. As part of its plan to expand storage capacity, Keystone is holding this open season to secure expressions of interest in firm gas storage services for 1bn cf of capacity from a fifth cavern that is currently being mined and anticipated to be in service by early 2006. It is also seeking expressions of interest for firm gas storage services from three proposed caverns (6, 7 and 8), that also would offer 1bn cf of capacity each. Keystone has applied to the Texas Railroad Commission for permits to develop these three caverns.

Located in the Permian Basin near the Waha hub, Keystone is a high-deliverability salt cavern natural gas storage facility. Regulated by the Railroad Commission of Texas as an intrastate facility, Keystone connects to the El Paso Natural Gas, Transwestern Gas Company and Northern Natural Gas Company pipelines. In January, Keystone requested and received approval from the Federal Energy Regulatory Commission (FERC) to provide gas storage services for interstate customers for up to 5bn cf of gas at market-based rates. FERC approval and Keystone's pipeline connections allow it to serve customers in Texas as well as the Midwestern and Western interstate markets.

Keystone has been in service since September 2002. At its current capacity of 3bn cf, Keystone's deliverability capacity is 200mn cf/d and its injection capacity is 100mn cf/d. Upon the expected completion of the facility's fourth cavern in late 2004, Keystone would have a total of 4bn cf of capacity in service.

UK business community goes for diesel cars

The UK business community has gone for diesel in a big way, with 67% of company cars, two out of every three, now running on it, according to UK fleet and fuel management company Arval PHH. Clive Forsythe, Arval PHH's Sales Director, comments: 'The company car tax changes of 2002 made diesels significantly more attractive to employees, because their lower carbon dioxide (CO_2) emissions meant for lower tax bills. These vehicles are also more appealing to companies because of their fuel efficiency. Moving forward, the introduction of sulphur-free fuels and improvements in diesel engine technology – with features such as particulate traps – will make choosing diesels a sound environmental decision.'

'In fact, one of the main problems with diesels in the past has been the 3% tax surcharge payable because of their high particle emissions. However, the new Euro 4 diesels that manufacturers are beginning to offer in the UK are exempt and so are even more tax-friendly. By including Euro 4 models on choice lists and letting their drivers know which vehicles qualify, companies are helping their employees towards lower tax bills and more efficient motoring.'

Forsythe also notes that although some businesses have introduced cash allowance schemes as alternatives to the company car, most still favour leasing packages such as contract hire.

UK Deliveries into Consumption (tonnes)

Products	†Jun 2003	†Jun 2004	†Jan–Jun 2003	†Jan–Jun 2004	% Change
Naphtha/LDF	199,990	139,273	1,186,871	1,167,564	–2
ATF – Kerosene	845,090	937,847	4,834,446	5,037,444	4
Petrol	–	–	–	–	–
of which unleaded	1,534,001	1,568,257	9,459,144	9,508,267	1
of which Super unleaded	72,666	81,306	403,089	427,502	6
ULSP (ultra low sulphur petrol)	1,461,335	1,486,951	9,056,055	9,080,765	0
Lead Replacement Petrol (LRP)	19,702	5,888	116,427	40,949	–65
Burning Oil	500,386	211,884	2,422,409	2,376,323	–2
Automotive Diesel	1,371,267	1,582,229	8,348,979	9,271,835	11
Gas/Diesel Oil	538,355	487,411	3,114,821	3,173,393	2
Fuel Oil	247,393	141,628	1,209,735	1,231,991	2
Lubricating Oil	69,147	78,286	420,169	398,406	–5
Other Products	744,412	862,939	4,024,150	5,028,987	25
Total above	6,069,743	6,015,642	35,157,121	37,235,160	6
Refinery Consumption	399,746	387,336	2,384,588	2,520,128	6
Total all products	6,469,489	6,402,978	37,541,709	39,278,215	5

† Revised with adjustments

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

High prices spur development rush as North Sea production declines

Soaring crude prices have already led to a whole series of small development projects being fast-tracked to production across the North Sea, reports *Chris Skrebowski*.

BP's Clair deck left Amec's Wallsend, Tyne and Wear, yard on 29 June. The oil field is due onstream in late 2004

The UK sector has seen BP press ahead with development of the 2003 Farragon oil find in block 16/28 as a two-well tie-back to Andrew, with a January 2005 start-up and a potential peak flow of 40,000 b/d. Meanwhile, ChevronTexaco has announced the go-ahead for Captain C, a subsea development of another sector of this well established North Sea heavy oil field. ExxonMobil is to develop the 130bn cf Arthur gas field (ex Camelot SE) as a tie-back to Thames for an end-2004 start-up. Tullow is planning to develop the Horne and Wren gas fields in blocks 53/3c and 53/4b, with production flowing via Thames and giving a combined flow of 90mn cf/d after start-up in April 2005.

The Norwegian sector has just seen the go-ahead on Marathon's Alvheim project. Because of its much greater size this will not be onstream until 2007. The combined reserves of Kneler, Boa and Kameleon are 180mn boe and if, as is likely, the Klegg discovery is added into the Alvheim development, the reserves rise to 200–250mn boe – making it a significant project. The latest status of all the other North Sea projects is detailed in **Table 1**.

Field discoveries

Although discovery is now at relatively low levels, it is still occurring. Current discovery rates have averaged around 150mn b/y in the UK sector and about 280mn b/y in the Norwegian sector over the last five years – but on a declining trend. According to UKOOA's *2004 Economic Report* exploration and appraisal expenditure in 2003 was £400mn, with indications that 2004 levels would be around 12.5% higher – although it does note that discovery size in recent years has been in the 20–30mn boe range, which means that even with high prices they need to be fairly close to existing infrastructure if they are to be developed. This lack of prospectivity compared with less mature basins is partly offset by the attractions of political and financial stability allied with ready access to skilled personnel, contractors and fabricators.

Recent discoveries are itemised at the end of each country section in **Table 1**. However, the Brenda oil discovery by Oilexco in block 15/25b came too late to be incorporated. On test, the find flowed 3,351 b/d – hinting that in a high price environment and close to existing infrastructure it could become a development project.

Good news

Further positive news comes with the idea that managements, on the technical side, are becoming more comfortable with subsea completions and extended tie-backs to existing infrastructure while, on the commercial side, rationalising assets and shareholdings has become an everyday activity.

The technical problems of handling multiphase flows over extended distances have increasingly been met, which means long-distance (over 30 km) tie-backs are becoming increasingly common. This, in turn, means that the size of the circle around existing infrastructure in which small accumulations can be tied back has increased.

The point has now been reached where a high proportion of the North Sea that has been proved to contain oil and gas can now realistically be developed by tie-backs to existing infrastructure. This gives considerable confidence that a high proportion of all the known small discoveries will, over time, be developed. Realistically, there are probably between 80 and 90 small discoveries in the UKCS that could be developed in a high price environment.

According to UKOOA's *2004 Economic Report* some £1.3bn of UK sector assets were traded in 2003, with the sale of BP's holdings in Forties to Apache being the largest single deal of the 27 involving commercial fields. In 2003 around 550mn barrels of UKCS reserves are reported to have changed hands.

The UK's 21st licensing round was generally regarded as a success, with 88 new licences awarded to 62 companies. The round saw the introduction of the low-cost 'Promote' licence that allows a company up to two years to work up a prospect before committing to a full licence with its obligations and benefits. The Promote licence has attracted considerable interest, with 53 awarded in the round – of which 27 went to new entrants to the UKCS.

Great hopes have been expressed that the smaller companies coming into the area with innovative ideas and approaches will become the new explorers and developers of the resources. This has happened, but as prices have risen there has been a tendency for some of the established majors to develop even quite small accumulations themselves rather than selling them and rationalising their portfolios.

For all the major infrastructure owners the key concern remains to maximise the return from their assets by loading them up and postponing abandonment for as long as possible. One emerging area of concern is the safety certification and recertification of ageing infrastructure in such a hostile environment.

	1999	2000	2001	2002	2003	2004*	2005*
Norway	3,139	3,346	3,418	3,330	3,262*	3,246*	3,160
UK	2,893	2,657	2,476	2,463	2,431*	2,135*	2,000
Denmark	301	364	347	371	377	414	380
Netherlands**	20	20	35	46	47	45	40
Germany**	22	21	21	20	20	19	18
Total	**6,375**	**6,408**	**6,297**	**6,230**	**6,137**	**6,128**	**5,598**

Source: BP Statistical Review *June 2003 except* * IEA Monthly Oil report *July 2003*
** Petroleum Review *estimate*

Table 1: North Sea oil production (,000 b/d)

	1999	2000	2001	2002	2003
Norway	48.5	49.7	53.9	65.4	73.4
UK	99.1	108.3	105.8	103.1	102.7
Denmark	7.8	8.1	8.4	8.4	7.9
Netherlands	19.9	19.8	20.0	20.0	23.0
Total	**175.3**	**185.9**	**188.1**	**196.9**	**207.0**

Table 2: North Sea gas production (bn cm)

Few large developments

Despite the recent flurry of activity and high prices improving prospects, the key challenge remains that the North Sea is a high-cost mature province with few large fields awaiting development.

In the UK, two reasonably large developments are due to come onstream this year – BP's Clair field to the west of Shetland (see p26) and Shell's Goldeneye. The Clair development will access 267mn barrels of recoverable oil as the first phase in the development of this very large, but complex, heavy oil field. Shell's Goldeneye is a 500bn cf gas/condensate field. With 17mn barrels of recoverable condensates, it is being developed via a not normally manned platform and a 105-km tie-back to St Fergus on the Scottish mainland, where the gas production will be processed and the liquids separated.

In 2005, the two largest developments by reserves will be the 123mn boe Devenick field and the 800bn cf Rhum field, both operated by BP. The year 2006 will see what, for the moment, is the last large UKCS field coming onstream. Encana's 550mn barrel Buzzard field is being developed with three bridge-linked steel platforms.

Future prospects in terms of large developments are not much greater in the Norwegian sector This year, 2004, features no large developments – however, 2005 will see the start-up of the Kristin field, the Ekofisk growth redevelopment, the Øseberg West flank development and the Visund gas field development. The following year, 2006, will see the start-up of the Alvheim project mentioned earlier, as well as the Snøvhit gas and LNG development. In 2006, the giant Ormen Lange gas field is due onstream – set to become a key supplier of gas to the UK via the planned Langeled pipeline from Ormen Lange to Easington on the East Anglian coast of the UK.

UK imports

The UK is likely to become a net gas importer from 2005/2006. (It is already a net importer in the Dec/Jan/Feb period, but a net exporter for the rest of the year.) By 2010 the existing Bacton-Zeebrugge interconnector could be bringing in up to 24bn cm of gas, and the existing Vesterled pipeline another 10bn cm. Starting up in mid-2006, the Langeled pipeline will bring in up to 25bn cm of Ormen Lange gas by 2010, while links across the median line could bring in a further 10bn cm.

In addition to the pipeline gas supplies, the UK will recommence LNG imports. BP and Sonatrach are planning to import LNG through the Isle of Grain, starting either later this year or in early 2005 with flows building up to 10bn cm by 2010. In 2007/2008 two LNG import terminals at Milford Haven will start up. The Petrolplus/BG/Petronas facility will import up to 10bn cm of LNG, while Qatar Petroleum/ExxonMobil will have a facility that is twice as large and able to bring in up to 20bn cm.

The UK is also set to become an oil importer once again, almost certainly around 2007/2008. By 2010 imports could be running at 0.5mn to 1mn b/d, largely depending on how successful the industry is in developing the remaining known discoveries and in 'squeezing the rocks' harder in the established fields.

The current situation is that by the start of 2004 the UKCS had produced 33bn boe, with 7bn boe remaining in producing fields and those under development. Additional reserves that could potentially be developed from 'brownfields'(existing developments) is estimated at between 3bn and 5bn boe, while the undeveloped discoveries are estimated to contain around 8bn boe.

The most problematic figure of all is the exploration potential of 5bn to 11bn boe. It is problematic because, at the current discovery rate of under 150mn boe/y, it will take 33 to 73 years to achieve.

North Sea overview

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
Onstream 2003								
*Ardmore (Argyll redev)	oil	30/24	Tuscan Energy	Oct-03	20–25mn b		4 highly deviated from JU	40,000 b/d (2004)
*Blake flank	oil	13/24a, 24b, 29b	BG	Sep-03	20mn b		2 wells tied back	
*Braemar	gas/cond	16/3c	Marathon	Sep-03	9–10mn b (cond)	107–115bn cf	1 subsea well to East Brae	4,500 b/d (03), 46 mn cf/d (03)
Caledonia (Parlmnt)	oil	16/26	ChevronTexaco	Feb-03	10.3mn b	15mn boe	subsea to Britannia	10,000 b/d (04)
*Carrack (Cleaver Bank)	gas	49/14b, 49/15a	Shell	Nov-03	6mn b (cond)	300bn cf	plat, subsea to Clipper (85km)	4,000 b/d, 160mn cf/d
*Clapham	oil	21/24	Petro-Canada	Dec-03	19.5mn b		Triton FPSO v Guillemot NW	15,000 b/d (04)
*Jade NE Flank	gas/cond	30/2c	ConocoPhillips	2003	30mn boe (cond)		2 wells tied back	10–20,000 b/d (04)
Juno project (ECA2)	gas	47/3b, 3c, 4a, 4b	BG	Jan-03	300bn cf		subsea + Minerva plat.	300mn cf/d(2003)or 8.5mn cm/d
*Nuggets Ph II (N4)	gas	3/18c, 19a,b, 20a, 24a	Total	Oct-03	500bn cf		subsea	53mn cf/d (04)
Penguin A,C,D,E	hvy oil	211/13, 211/14	Shell	Jan-03	50mn b	175bn cf	subsea to Brent C (65km)	40,000 b/d (03), 70mn cf/d (03)
*Schiehallion Ph IV (Claw)	oil	204/20, 204/25	BP	2003	75mn b	or 163mn boe	3 prodn + 5 inject to FPSO	+30,000 b/d
Scoter	gas/cond	22/30a, 23/26	Shell	Nov-03	3mn b or 40mn boe	200bn cf	tieback to Shearwater	6,000 b/d (04), 120mn cf/d (04)
*Seymour	cond	22/05b	BG	Mar-03			subsea tie-back to Armada	
Sycamore (Pine,N,Elm)	oil	16/7, 16/12a	Venture	Mar-03	24mn boe	14bn cf	2 subsea to Brae A	27,000 b/d (04), 30.5mn cf/d (04)
South West Seymour	gas	22/5b	BP	Aug-03			tieback to Armada	
Onstream 2004								
*Alba Extreme South PhII	oil		ChevronTexaco	Nov-04			3 subsea to Alba	36,000 b/d (late-04)
Blane	oil	30/3a	Shell	2004?	15–40mn b		subsea tie-back to Pierce	15-25,000 b/d, 6-10mn cf/d (Ph1)
*Broom (ex W Heather)	oil	2/5	Lundin Oil	Aug-2004	22mn b		3 prodn, 2 inj tie back to Heather	20,000+ b/d (05)
Bruce (upgrade)			BP	2004			additional compression	
Boulton H (CMS III)	gas	44/21b	ConocoPhillips	Mar-04		106bn cf	via Caister Murdock (CMS)	140mn cf/d
Calder (Rivers)	gas	110/7a	Burlington	2004	2mn b (cond)	350–400bn cf	NNM platform	80mn cf/d (06)
Chiswick	gas	49/3a	Centrica	2004		120bn cf	platform	
*Clair South	oil	206/7a, 8, 9a, 12, 13a	BP	late 2004	267mn b (Ph I)	106bn cf	1 steel platform	60,000 b/d, 15mn cf/d (05)
Curlew A-D	oil	block 29/7	Shell	2003	20mn boe		subsea to Curlew	
Don redev. W, SE (SA)	oil	211/18a	BP	2004	35mn b	35bn cf	subsea tie back to Don	
Goosander	oil	21/12, 21/13a	Shell	2004	16mn b++		subsea to Kittiwake	15,000 b/d
*Goldeneye	gas/cond	14/29a, 20/4b	Shell	Oct-04	17mn b (cond)	500bn cf	NNM plat, 105km t/b St Ferg	30,000 b/d (05), 234mn cf/d (05)
Harding area gas	gas	9/23b	BP	2004			appraisal tie-backs to Harding platform	
Helvellyn	gas	47/10b	ATP	2004	50bn cf		subsea to Amethyst platform	36mn cf/d (for 5 years)
Howe	oil	22/12a	Shell	2004	15mn b	5bn cf	subsea tie-back to Nelson	
Jill & Julia (SA)	oil/gas	30/7a	ConocoPhillips	2004			subsea tie-back	
Nevis Centr'l(Ness Complex)	oil/gas		ExxonMobil	2004	9mn b		subsea	
Rivers Hodder/Crossans	gas	110/7a	Burlington	Mar-04	49,000 b (cond)	350–400bn cf	to NNM platform on Calder	80mn cf/d (06)
*Rose	gas	47/15b	Centrica	Jan-04		88bn cf	subsea via Amethyst	
Valkrie	gas	49/16	ConocoPhillips	2004		70bn cf	ERD	
Venture	gas	49/12a	ConocoPhillips	2004		50bn cf	subsea tie-back	
Onstream 2005								
Artemis (Juno)	gas		BG	2005		70bn cf		
*Atlantic & Cromarty	gas/cond	13/30a, 14/26a	BG/Am'rda Hess	late 2005	3mn b (cond)	250bn cf	tie-back to St Fergus	220mn cf/d (06)
Atlas/Hyperion/Rhea(Saturn)	gas	48/10b, 48/10a	ConocoPhillips	2005		240bn cf	6-slot NNM plat via LOGGS	170mn cf/d (06)
Caravel (Cleaver Bank High)			Shell	2005		390bn cf	plat	
Cavendish Area +East	gas	43/19a	RWE-DEA	2005		175bn cf	subsea to Trent	51mn cf/d (2004)
Chestnut PhII	oil	22/2a	Venture	2005		16mn b	subsea	18,000 b/d
Clipper South	gas		Shell	2005		350bn cf		
Curlew C	oil/gas	29/7	Shell	2005	18mn b	35bn cf	subsea to Curlew	
Devenick	oil	9/24b	BP	2005	123mn boe	480bn cf	plat or tie-back to Harding	
Ettrick	oil	20/2a	Shell	2005	35mn b		FPSO or subsea	
Enoch/J1	oil/cond	16/13a	Shell	2005	10.4mn b	67bn cf	subsea to Miller or Brae	10,000 b/d (03), 15mn cf/d (03)
*Fiddich (ETAP III)	gas/oil	CNS	BP	2005	5mn b (cond)	105bn cf	2 well tie-back to Marnock	2,000 b/d cond (06), 40mn cf/d (05/6)
*Glenelg	oil/gas	29/4d	Total	3Q2005	40mn b (cond)	200bn cf	High dev ERW from Elgin	12,000 b/d (cond) + gas
Jacqui	oil/gas	30/13	ConocoPhillips	2005	10mn b	70bn cf	subsea to Judy	10,000 b/d (05), 50mn cf/d (05)
Magnus NW	oil	211/7a	BP	2005	10mn b		ERD	
Orca and Minkie	gas	44/24a, 29b, 30	Gaz de France	2005		282bn cf	wellh'd plat to D/15-FA	72mn cf/d (03)
Perth	oil/gas	15/21b	Encana	2005	33mn b	35bn cf	subsea to Scott	20,000 b/d (05)
*Rhum	gas/cond	3/29a	BP	Oct-05	5mn b (cond)	800bn cf	3 subsea tie-back 44km to Bruce	300mn cf/d (16 years)
Seagull	oil/gas	CNS	Shell	Jun-09	16mn b	35bn cf	subsea	
Topaz	gas	SGB	RWE-DEA	2005		50bn cf	subsea	
Onstream 2006								
Alder	gas/cond	15/29a	ChevronTexaco	2006	30mn b (liquids)	250bn cf	subsea tie-back	
*Brodgar & Callanish	gas/oil	21/03a, 15/29b, 21/4	ConocoPhillips	2006	40mn b +20mn b (cond)	175bn cf	subsea to new Britannia facil	35,000 b/d, 200mn cf/d
*Buzzard	oil	19/5, 19/10, 20/1, 20/	EnCana	end 2006	550mn b		Three steel plats	180,000 b/d (07/8)
Forvie North	gas/cond	3/15	Total	2006	40mn boe		via Dunbar?	
Kessog (SA)	gas/cond	30/01c	BP	2006	60mn b (cond)	260bn cf	unmanned plat or subsea	
Macallan	gas/cond	CNS	ConocoPhillips	2006	5mn b (cond)	50bn cf	subsea tie-back	
Puffin	oil/gas	29/4a, 5a, 9a, 10	Shell	2006	25mn b + 40mn b (cond)	260bn cf	wellh'd plat to Shearwater	18,000 b/d (08), 150mn cf/d (08)
Onstream 2007								
Rivers2 Crossans/Darwen	gas	110/2b, 110/7a	Burlington	2007		120bn cf		
Wood (SA)	oil/gas		Paladin	2007				
Possible dev's								
Alwyn North Trias			Total					
Amy and Argo area	gas	48/10b,48/9a	ConocoPhillips			370bn cf	plat	
Anglia	gas							
Ani			Shell				subsea tie-back	
Appleton area	gas/cond	30/11	Talisman		40mn b	60bn cf		
Arbroath/Montrose	oil	22/17, 18	BP				Poss comp plat	Auk North
	oil	30/16	Shell		25–30mn b		subsea to Auk	
Babbage	gas	48/2a	TXU		165bn cf		subsea to Johnston	
Bedevere	gas	48/14	ExxonMobil			100bn cf	ERD	40mn cf/d (04)
Beechnut	oil/gas	29/9b	Amerada Hess				subsea tie-back or FPSO	20,000 b/d
Bennachie	oil	21/15a, 15b	Shell		15mn b		subsea to Forties or Nelson	10,000 b/d
Beta (UK)	gas	44/24a	Consort			75bn cf	wellh'd plat to Orca	35mn cf/d (04)
Block 15/23	cond	15/23d	BG					
Block 16/26	oil	16/26a	BP				plat	
Blythe	gas	48/22a, 48/23a	Tullow				via Hewett	

Table 1: North Sea fields onstream in 2003 and beyond

continued overleaf...

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
Bressay	hvy oil	3/28a	ChevronTexaco		200mn b			
Brigitte	gas		BG					
Dolphin		22/18	BP					
Ensign	gas	48/14	Centrica				plat	
Flyndre			Total				subsea tie-back	
Fyne/Dandy	oil	21/28a	Lasmo		39mn b		FPSO?	
Glenn			BP				subsea tie-back	
Hunter	gas	44/23a	Total				subsea tie-back	
Johnston Gamma			BHP				ERW	
Josephine	oil/gas	30/13	ConocoPhillips		30mn boe	95bn cf	subsea to Judy	8,000 b/d, 50mn cf/d
Kate/Turnstone	oil/gas	22/23b, 28a	BP?		73mn boe	20bn cf	subsea	20,000 b/d, 15mn cf/d
Kildrummy (Lucy)	oil	15/12b, 15/17	Talisman		40mn b	25mn boe	subsea tie-back to Piper B	
Lennox West			Burlington				subsea	
Mandarin	oil	22/23b, 22/28d, 22/28a	Shell					
Marcel/Bravo								
Mariner	hvy oil	9/11a	ChevronTexaco		100mn b		project on hold	
Melville		210/24b	Amerada Hess				subsea	
Mirren	oil/gas	22/25b	Shell				subsea	
Nevis Far North			ExxonMobil				ERW	
Peik UK	oil/gas	9/15a	Total		20mn b	350bn cf	subsea to Beryl A	9,000 b/d, 110mn cf/d
Pilot	oil	21/27	Total		77mn b		floater?	
R Block	oil	15/27	ConocoPhillips					
Ramsay	gas	53/5b	BP			75bn cf	ERW from Davy?	
Skye	oil	211/23a, 23c	Shell		20mn b		subsea to Dunlin	11,000 b/d
Solan/Str'thm're (SA)	oil/gas	204/30	Amerada Hess				FPSO	40,000 b/d
Suilven	oil	204/19	BP					
Thebe	gas	49/22	ConocoPhillips			74bn cf	with ECA Ph II	35mn cf/d
Tornedo	oil	22/23b, 28a, 28c	Shell		30mn b			20,000 b/d
Wissey	gas	53/04	BP				subsea	
Wood (SA)	oil/gas	22/18	Nisus/BP		15mn boe		1–2 subsea to Arbroath	
York	gas	47/3a	Amerada Hess		test 24.7mn cf/d	200bn cf		
KEY DISCOVERIES								
close to Buchan	oil/gas	21/1a-20	Talisman		10–40mn b in place			
close to Brigantine	gas	49/20a, 49/20b	Shell					
West Franklin	gas/cond	29/5b	Total		test 1mn cm/d,2kb/d (cnd)			
close to Buzzard	oil		Edinburgh O&G		30mn b			
Brechin	oil	22/23a	Paladin		110ft (oil sands)		via Arkwright	
Annabel	gas	48/10a	Venture	2005	100mn cf/d		via Audrey facils	
Farragon	oil	16/28	BP		30mn b		via Andrew	
Montrose North	oil		Paladin				via Montrose	
5 miles from Camelot	gas	53/2	ExxonMobil		65mn cf/d on test			
Tartan North Terrace	oil	15/16a	Talisman		8,100 b/d on test			
NETHERLANDS								
2003								
K4b/5a	gas	K5a	Total	2003			plat	
K7-FB	gas	K7	NAM	2003			plat to K7-FD-1	
K12	gas	K12	Gaz de France	2003			S3 subsea to 12-1	
K15-FK	gas	K15	NAM	Jul-03			plat to K15-FB-1	4.5mn cf/d
L5-B	gas	L5	Wintershall	2003			plat to L8-P4	
Q1-B	gas	Q/1,Q/4	Wintershall	2003		400bn cf	plat t/b to Hoorn	34mn cf/d (2003)
2004								
D-12	gas	D12a	Wintershall	2004			plat (2 wells)	
L-06d	gas	L/6	NAM/ATP	2004				
Q5-A	gas	Q5	Wintershall	2004		21bn cf	subsea to Q8-B	
2005 and later								
A & B quadrant	gas	A12A	NAM	2005		400bn cf	plat	
F16-A	gas	F16/E18	Wintershall	Jan-06		450bn cf	1 steel plat, 5 wells init prodn 150mn cf/d	
G14	gas	G14a	Gaz de France	2005			plat + subsea	
G16-FA	gas	G16a	Gaz de France	2005		220bn cf	plat	
K/2-A	gas	K/2b	Gaz de France	2005		250bn cf	plat	
K4b/5a	gas	K/5a	Total					
L4-G	gas	L4	Total	2005		100bn cf	plat	
Probable dev's								
K/5-Fe	gas	K/5	Total	2002		80bn cf	plat	K/7-FB
	gas	K/7	NAM	2003		150bn cf	plat	
K/15-FE	gas	K/15	NAM	2003		30bn cf	plat	
K15-FJ	gas	K/15	NAM	2004		40bn cf	plat	
L/2-FB	gas	L/2	NAM	2003		85bn cf	plat	
L/9-6	gas	L/9A, L/9B	NAM	2003		100bn cf	plat	Minke (Neth)
	gas	M/7	NAM	2003		100bn cf	plat	45mn cf/d (2001)
Orca (Neth)	gas	D/15, D/18A	NAM	2003		104bn cf	plat	40mn cf/d (2002)
Q/1-A	gas	Q/1	ConocoPhillips	2004		400bn cf		
KEY DISCOVERIES								
K15	gas	K/15	Shell, ExxonMobil			300bn cf		
NORWAY								
Onstream 2003								
Fram West (Incl Sogn)	oil/gas	35/11, 31/2	Norsk Hydro	Oct-03	100mn b	3.5bn cm	subsea via Troll C	63,000 b/d (04)
Glitne II	oil	15/5, 15/6	Statoil	Sep-03	37mn b		subsea to Glitne FPSO	
Grane (Hermod)	oil	25/11	Norsk Hydro	Sep-03	705mn b (hvy oil)	1.8bn cm	PDQ platform	over 215,000 b/d (05-09)
Ringhorne II (plat)	oil	25/8, 25/10,11,	ExxonMobil	Feb-03	280mn b	2bn cm	PDQ platform via Balder	80,000 b/d, 28mn cf/d
Valhall Flanks	oil	2/8, 2/11	BP	May-03	additional 110mn b		2 wellhead platforms	60,000 b/d
Varg South	oil/gas	15/12	Pertra PGS	2003	40mn b	4bn cm	ERD well from Varg	
Vigdis Extension	oil	34/7	Statoil	Oct-03	60mn b		subsea to Snorre	
Onstream 2004								
*Kvitebjorn	gas/cond	34/11	Statoil	Oct-04	135mn b (cond)	52bn cm	PDQ plat	20mn cm/d, 62,500 b/d (cond)
*Mikkel	gas/cond	6407/6, 6407/5	Statoil	Feb-04	40mn b (cond)	28bn cm	4 subsea to Asgard B	30,000 b/d

Table 1: North Sea fields/gas onstream in 2003 and beyond

continued overleaf...

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
Øseberg J South	oil/gas	Norsk Hydro	Oct-04		24mn b	0.5bn cm	subsea to Oseberg South	21,000 b/d
*Skirne/Byggve	gas/cond	25/5	Total	Mar-04	10.7mn b (cond)	6.7bn cm	2 subsea to Heimdal	6,900 b/d, 150mn cf/d
Sleipner Alpha North	gas/cond	15/6	Statoil	2004	32mn b (cond)	13bn cm	subsea to Sleipner T	
Valhall water inject	oil	2/8, 2/11	BP	Jan-04	additional 150mn b		15 well plat to inj 210,000 b/d	
Onstream 2005								
*Åsgard Q	oil			2005				
Ekofisk Growth	oil/gas	block 2/4	ConocoPhillips	2005	156mn boe		wellhead plat +mods	
Gulltopp (ex Dolly)	oil	33/12	Statoil	2005	25mn b	500mn cm	ERW from Gullfaks A plat	
*Kristin (Halten Bank West)	gas/cond	6406/2-3, 11	Statoil	Oct-05	220mn b cond	34.9bn cm	12 subsea to FPU to Asgard	126,000 b/d (cond), 15mn cm/d
Lerke	oil	6608/10	Statoil	2005			subsea to Norne	
Njord Gas	gas	6407/7,10	Norsk Hydro	2005		10bn cm	plat modifications	
Øle/Dole	oil	33/12	Statoil	2005	13.2mn b	1.1bn cm	subsea Statfjord/Øseberg	
Øseberg Delta	gas/cond	30/9, 30/8	Norsk Hydro	2005	7mn b (cond)	4bn cm	subsea/ERD via Øseberg	
Oseberg West Flank	oil/gas	30/6	Norsk Hydro	2005	190mn b	6bn cm	subsea via Øseberg	
Skinfaks	oil	33/12	Statoil	2005	15.7mn b	1bn cm	subsea to Statfjord	
Svale/Staer	oil	6608/10	Statoil	late 2005	50mn b and 16mn b	0.2bn cm, 0.1bn c	8 subsea via Norne	70,000 b/d
Tommeliten Alpha	oil/gas	1/9	ConocoPhillips	2005	16mn b	3bn cm	subsea to Ekofisk?	
Troll A compression	gas	31/6	Statoil	2005			additional compression	
Visund Gas	gas	34/8	Norsk Hydro	2005	4.7mn t (NGLs)	50.5bn cm	via Visund F wells	
Volve	oil/gas	15/9	Statoil	Aug-05	75mn b, 0.5mn t (NGLs)	1.6bn cm	FPSO or jackup	40,000 b/d
Onstream 2006								
Alvheim	oil/gas	24/6, 25/4	Marathon	2006	152mn b	4.9bn cm	FPSO	80,000 b/d, 0.9mn cm/d
Fram East	oil/gas	35/11	Norsk Hydro	2006			subsea to Troll C	
Freja-Mjolner	oil	2/12	Amerada Hess	2007	18.2mn b	0.6bn cm	subsea to Valhall or Arne	
Gjoa	oil/gas	35/9, 36/7	Norsk Hydro	mid-2006	41mn b	29.4bn cm	subsea to Troll	
Goliat	oil	7122/7 (Barents Sea)	Agip	2006	50mn b		FPSO	
Gudrun	gas/cond	15/2, 15/3	Statoil	2006	87mn b (cond)	15.6bn cm	NNM plat to Sleipner/Brae	
Heimdal West	oil/gas	24/6, 25/4	Marathon	2006			FPSO or tie-back Heimdal	
*Snøhvit+ others	gas/cond	7120/5,6,7,8,9, 7121/4	Statoil	2006	114mn b (cond)	151bn cm	subsea 160km to Melkoya	20.8mn cm/d
Varg South	oil/gas	15/12	Pertra (PGS)	2006	25–30mn b	4bn cm	RD from Varg + subs	
Onstream 2007+								
Dagny	gas/cond	blocks 15/6 and 15/5	Statoil	2008	7.5mn b (cond)	3.8bn cm	subsea via Sleipner A	
Falk/Linerle	oil	6608/11	Statoil	2007	6.3mn b		subsea to Norne	
Freja-Mjolner	oil	block 2/12	Amerada Hess	2008	18.2mn b	0.6bn cm	subsea to Valhall or Arne	
Gjoa	oil/gas	35/9, 36/7		2008	50mn b	25bn cm		
Goliat	oil	7122/7	Agip	2008	50mn b		FPSO or subsea	
Gudrun	gas/cond	15/3, 15/2	Statoil	2008	91.2mn b oil/cond	7.7bn cm	plat to Sleipner	
Idun (ex Fangst)	gas	6507/3	Statoil	2008	1mn b, 1.3mn t NGLs	8.1bn cm	subsea to Skarv?	
Lavrans	gas/cond	6406/2	Statoil	2008	24.5mn b (cond)	13.9bn cm	subsea to Kristin	
*Ormen Lange	gas/cond	6305/4,5,7,8	Norsk Hydro	2007	182mn b (cond)	397bn cm	processing plat	50mn cm/d, 20 year plateau
Peik	gas/cond	24-Jun	Total		7.5mn b	5.3bn cm	subsea	
Skarv	gas/cond	6507/3,5,6	BP	2008	104mn b,10.3mn t NGLs	33.3bn cm	FPSO or tie-back to Heidrun	16mn cm/d, 100,000 b/d
Trym	gas/cond	block 3/7,3/8	Norske Shell	2008	5mn b (cond)	3.3bn cm	subsea to Arne South	
Tyrihans N &S	oil/gas	6407/1, 6406/3	Statoil	2009	151mn b oil/cond	30bn cm	subsea to Åsgard or Kristin	
Valemon	gas/cond	34/10, 34/11	Statoil		8.2mn b (cond)	12.8bn cm	subsea to Kvitebjorn	
Valhall Redevelopment	oil/gas	2/8, 2/11	BP	2007			process/accom plat	150,000 b/d, 4.25mn cm/d
KEY DISCOVERIES								
Lerke	oil	6608/10	Statoil					
Hvitveis	gas	6706/6	ExxonMobil					
Kneler	oil	25/4	Marathon Oil				West Heimdal Area	
Boa	oil/gas	24/6,	Marathon Oil					
Hamsun (Nr Alvheim)	oil/gas	36792	Marathon Oil				tie-back to Alvheim	
Klegg	oil	25/4	Norsk Hydro		120mn b		Alvheim Development	
Verdandi	gas	16/1	Statoil					
DENMARK								
2003								
Cecilie/Nini + Connie	oil	5604-20, 5605-10	DONG	2003/04	65mn b		2 wellhead plats via Siri	17,000 b/d
Halfdan North-East (Igor/Sif)	oil/gas	5505/13	Maersk	2003	7mn b	15bn cm	plat to Dan F, Tyra	
2004								
Dan FG	gas	5505/07	Maersk	2004			gas processing platform	6.8mn cm/d
Halfdan III	oil/gas	5505/13	Maersk	2004	486mn b	8.6bn cm	two jackets + bridge	100,000 b/d
Siri East Segment	oil	5605/13	DONG	2004	15mn b		subsea to Siri	
Stine	oil		Paladin	2004				
2005 and later								
Adda	oil/gas	5504/8	Maersk	2005	6mn b	1bn cm	subsea or NNM to Tyra	
Alma	oil/gas	5505/17	Maersk	2007	6mn b	1bn cm	plat to Dan F	4,000 b/d, 22mn cf/d
Amalie	gas/cond	5604/26	DONG	2007	13mn b (cond)	3bn cm	plat to South Arne	7,000 b/d, 42mn cf/d
Boje	oil	5504/7	Maersk	2007	5mn b		subsea to Roar/Valdemar	
Elly	oil/gas	5504/6a	Maersk	2007	6mn b	1bn cm	NNM plat to Tyra	
Freja-Gert	oil	5603/27, 28	Maersk		7mn b	1bn cm	subsea	
Hejre	oil	5603/28	ConocoPhillips	2007			plat to South Arne	
*Valdemar Extension	oil/gas	5504/7, 5504/1	Maersk	2005			plat + pipeline	
KEY DISCOVERIES								
Sofie-1	oil	20km northeast of Siri	Paladin	2004			tie-back to Siri	
IRELAND								
Corrib	gas	18/20, 18/25	Shell	2006		850bn cf	subsea to shore	
Greensand	gas	48/25	Marathon	2003			subsea to Kinsale B	
Seven Heads	gas	48/22, 48/23	Ramco	Dec-03		300bn cf	6 subsea to Kinsale A	
KEY DISCOVERIES								
Dooish	oil/gas	12/2-1	Shell	2010	up to 400mn boe			

Table 1: North Sea fields onstream in 2003 and beyond

continued overleaf...

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Look out for updates and the full programme in forthcoming issues of *Petroleum Review* or visit www.ipweek.co.uk for more information.

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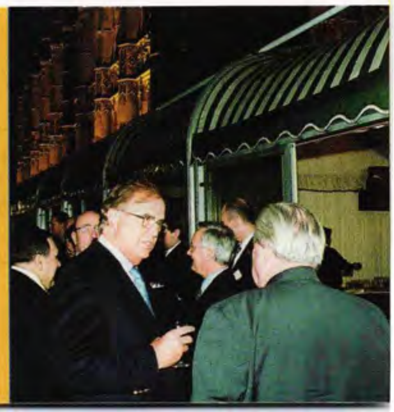

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New treaty to boost activity

Work on the Snøhvit terminal is running behind schedule, which may lead to the start-up target of October 2006 being delayed
Photo courtesy of Statoil/Eiliv Leren

The long-awaited Norway/UK treaty is finally expected to be signed in the autumn. It has been a long time coming, as the two governments announced last October that the principles had been agreed. However, the wait should be worthwhile, as it will open the way to implementing a growing number of cross-border projects. *Nick Terdre* provides a quick round-up of some of these pending projects.

The most pressing matter that comes under the *aegis* of the treaty is gas supplies from Norway to the UK. To some extent transport arrangements can be made under existing provisions – platform-to-platform pipelines, for example – but the new treaty will be more comprehensive than these and should make cross-border projects much easier to implement.

The major project that currently depends on the treaty is Langeled, the 1,200-km pipeline which will carry Ormen Lange gas from the Norwegian Sea via Sleipner to a new terminal at Easington. The international part of the line is due to come into operation in October 2006, carrying third-party gas. Ormen Lange gas is due to start flowing a year later.

Several other cross-border gas pipelines have been proposed. Statoil plans to export Statfjørd gas to the Flags system via Brent. BP also favours a link to Flags as the preferred evacuation route for gas from the Skarv field in the Norwegian Sea – at 620 km, this will be another lengthy line. Marathon has decided to export gas from the Alvheim development to the UK via a link to the Sage system.

Cross-border tie-backs

There are also a number of upcoming developments which could involve cross-border tie-backs. Some are fields

Nick Terdre reports on recent North Sea developments outside the UK and Norwegian Continental Shelves.

Netherlands

The Dutch Government, which ran into a storm of criticism last year when it abolished depreciation at will in a bid to temporarily raise the tax-take, may be on the way to having second thoughts. As the industry continues to lament the negative effects on offshore investment, it has decided to review the situation after only one year instead of the three originally intended. The outcome is expected to be made known in the autumn.

The level of development activity across the sector is patchy. While companies like NAM and Total are virtually inactive, others like Gaz de France (GdF) and Wintershall are relatively busy. In mid-year GdF was out to bid for the fabrication, installation and pipelay required for four new gas developments – in K2b, G14a (two) and G17cd.

The K2-A platform will have wellhead and processing facilities, and export through a short spur into the NGT trunkline. The G-quad projects will require a new processing platform, G17-AP, which will be bridge-linked to the existing G17cd-A platform. The topsides from the redundant K11-B and K12-E platforms will be installed on G14-A and G16a-A, while the wellhead and tree from K12-S1 will be reused on G14-S1.

Platform installation is scheduled for summer 2005 followed by start-up late in the year. One to two wells will be drilled on each field using two Noble jackups, *Piet van Ede* and *George Sauvageau*.

Wintershall has awarded the main contracts for the F16 development – platform fabrication and installation to Heerema and pipelay to Allseas. The 5,000-tonne platform will be installed in summer 2005 and tied back to the NGT trunkline by a 32-km, 24-inch pipeline. Start-up is scheduled for January 2006.

Meanwhile the company aims to bring D12-A onstream late this year, within a year of sanction. The platform, built by Nami, was due for installation in August, and in late summer the Subsea 7 layship *Skandi Navica* was expected to install a 5-km, 10-inch pipeline to D15-FA1.

Following on from sanction in April, PetroCanada is now pushing ahead with the €250mn development of the De Ruyter oil field in P10. As on the operator's Hanze field, the production unit will be a gravity-based structure with storage tanks in the base. Crude will be exported by tanker and gas by pipeline. Detailed design is being carried out by Amec and fabrication will be tendered later this year. The topsides will consist of an integrated deck with wellhead and processing facilities. Three wells will be drilled. The platform is due for installation in mid-2006, followed by start-up later that year.

The looming shortfall in UK gas supplies has prompted a new pipeline project – the Balgzand-Bacton Line (BBL). The owners, Gasunie, Fluxys and E.On Ruhrgas, decided in May to implement the €500mn project after getting the green light from the European Commission. The 235-km, 36-inch line, which will be operated by Gasunie's transport arm, Gas Transport Services, will have capacity of about 16bn cm/y. First shipments are due to flow in autumn 2006.

Heerema crane-barge *Thialf* prepares to install NAM's K7-FB-1 deck.
The platform was installed and came onstream in 2003.
Photo: Heerema Marine Contractors

Denmark

Denmark's first gas supplies are due to start flowing to the Netherlands in October through the new €50mn Tyra West to F3 pipeline. Operated by Mærsk and owned by Dong and the DUC partners, the 100-km, 26-inch line, which has an annual capacity of 5.5bn cm, was laid by Allseas' layship *Solitaire* early this year.

Gas from Mærsk's Halfdan North-East development looks set to take this route. The first well drilled under this project, a gas producer into the Sif field from the Halfdan HBA satellite platform, was tested last autumn and then suspended pending start-up of the pipeline. Gas is exported from HBA to Tyra West via a 27-km, 24-inch line installed by *Solitaire* last autumn.

Mærsk has now embarked on a fast-track incremental development on the Valdemar field. The plan, which calls for eight new wells, was approved by the Danish Energy Agency in June. As all the well-slots on the existing platform have been used, a new Star platform will be installed alongside it in summer 2005. Separation facilities will also be installed, enabling wet gas to be exported. A 15-20 km pipeline to Tyra West will be laid for this purpose.

Connie, which was drilled from the Cecilie platform by jackup *Ensco 70*, came onstream in July 2004
Photo: Dong

In May Dong brought onstream Siri East Segment 1, its first subsea development. One production well has been drilled and tied back nine km to the Siri platform, and a water injection well will be added in the autumn.

Having brought Cecilie and Nini onstream last September with wellhead platforms tied back to Siri, Dong has now developed the small Connie field by means of an extended-reach well drilled from Cecilie. Connie began producing in July.

Ireland

Shell's Corrib project is back on the rails again – at least for the time being. In spring the company received planning permission from Mayo County Council for its revised proposal for the onshore terminal. Previous plans had foundered on environmental objections. Assuming the application survives the appeals that have been lodged, the project could be free to proceed by September, in which case start-up could be expected in late 2006. Although the onshore construction contracts have been terminated, Allseas' pipelay contract is still in place. However, Shell is to retender umbilical installation.

Two gas fields – Ramco's Seven Heads and Marathon's Greensand – came onstream late last year, although production on Seven Heads has since been interrupted by water build-up in the subsea wells.

that straddle the border, such as Paladin's Blane and Enoch, for which the company aims to finalise development plans before year-end. Blane is said to be a test case for cross-border cooperation. Another field that straddles the border is Peik, for which Total sees potential hosts in Bruce or Beryl on the UK side, or Heimdal on the Norwegian side. Statoil's Gudrun, which lies wholly on the Norwegian side, could be tied back to Brae or Miller in the UK.

Other recent developments include the award of the main contracts for the NKr66bn (€7.8bn) Ormen Lange project. Aker Kvaerner has done well, winning a construction contract for a major part of the onshore plant and the order for subsea equipment. In the first phase eight wells will be drilled through two subsea templates by Smedvig's drillship *West Navigator*. Contracts for laying the pipelines to shore and the Langeled pipeline have been awarded to Saipem UK, Allseas Marine Contractors and Stolt Offshore. Start-up is set for October 2007.

Marathon's Alvheim is the largest development project undertaken by a foreign operator for some years – reserves are estimated at 152mn barrels of oil and 4.9bn cm of gas. Following development approval, which is expected in the autumn, the company aims to achieve start-up in late 2006. It has an agreement to acquire Statoil's multipurpose shuttle tanker *Odin* for conversion into an FPSO. Up to 17 wells will be drilled on the Kameleon, Boa and Kneler fields.

This spring Marathon discovered fresh reserves at Hamsun and Grieg, which are likely to become second-phase tie-backs to the production ship. Another possible tie-back is Norsk Hydro's Klegg discovery some 21 km to the north-east.

More recently, in July, Statoil received official approval for the development of the Norne satellites Stær and Svale. They will be developed with subsea wells tied back to the Norne ship by a common pipeline. The chances of further developments in the area have been strengthened by the successful appraisal this year of the Alve gas/condensate field and an oil find at Linerle, close to the existing Falk discovery.

Snøhvit delays

However, the news from Statoil's flagship Snøhvit LNG project in northern Norway has not been going to plan. Construction of the LNG plant at the Dragados yard in Spain is running behind schedule and, if the 2005 window for transporting the plant to the terminal near Hammerfest is missed, the start-up target of October 2006 could be postponed. Dragados was also running late with fabrication of the riser balcony for the Kristin floating production unit, which Statoil decided to have completed at Aker Stord, where the platform is being built. Kristin, a gas/condensate field in the Norwegian Sea, is still expected to achieve start-up on schedule in October 2005.

Of the new fields due onstream this year, Statoil's Kvitebjørn, also a gas/condensate field, is the largest, with 52bn cm of gas and 135mn barrels of oil reserves. It has been developed with a platform, whereas all the other start-ups – Total's Skirne/Byggve, Hydro's Øseberg J South and Statoil's Sleipner West Alpha North – are subsea tie-backs.

Raising exploration hopes

The 18th round awards in June have raised exploration hopes again, and several companies have moved quickly to commission seismic surveys. Three of the 16 operatorships went to smaller companies – Paladin, Pertra and RWE-Dea. Frontier acreage has been awarded not only in the Norwegian Sea but also in relatively unexplored areas of the North Sea. Paladin's acreage includes the decommissioned Yme field, which the company said might be redeveloped.

Statoil and Hydro are planning a three-well exploration campaign in the Barents later this year, after the government lifted its ban on activity. However, to the chagrin of the industry, prospective areas around the Lofoten Islands in the northern Norwegian Sea remain off limits. In June Einar Steensnæs, the Oil and Energy Minister responsible for these embargos, was replaced in a cabinet reshuffle by Thorhild Widvey, but it is not thought likely that any significant policy changes will ensue.

energy INSTITUTE

Seminar on Respiratory Protective Equipment – the facts about fit testing

Friday 8 October 2004

Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK

The Energy Institute's (EI) Occupational Hygiene Committee will be hosting a 1-day seminar on Respiratory Protective Equipment (RPE). The seminar will include presentations from a number of key groups, including the Health and Safety Executive (HSE) on current and future requirements and expectations, a view from manufacturers on design aspects, industry views on practical aspects of fit testing and a view on the medical aspects of RPE.

The seminar will be of interest to anyone involved with the use of RPE as a means of controlling exposure to airborne hazards, including policy makers, managers, operational and emergency response team members.

For further details on the technical aspects of this event please contact:
Martin Maeso, Technical Team Manager at the EI.
t: +44 (0)20 7467 7128 f: +44 (0)20 7467 7156 e: mmaeso@energyinst.org.uk

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Tickets:
Member: £40+VAT
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If you would like any further information on the programme or booking your place, please contact:

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energy INSTITUTE

Oil Depletion – No Problem, Concern or Crisis?

Wednesday 10 November 2004
Energy Institute, London

There is mounting concern that oil supplies may peak in the relatively near future. A rash of recent books and articles have concluded that the cheap oil era is over and that fairly soon supplies will fall short of demand with almost incalculable impacts on our oil-addicted societies. Recent high oil prices and Middle East instability have heightened supply concerns. As if this was not enough, doubts have recently been raised about Saudi Arabia's ability to supply future requirements and about the real size of Middle East reserves.

So has oil depletion reached the point where it will restrict supply? Is the fundamental driver of future oil supplies geology? Or is there little or no supply problem because economics — prices and investment – are the real keys to future supplies?

The conference will tackle all aspects affecting future oil supplies – geological, financial, economic and political. Speakers from a range of backgrounds and interests will discuss all aspects of oil depletion and attempt to answer the question as to how concerned we should be about future oil supplies.

An extended panel discussion among the speakers and guests will take the debate forward with particular emphasis on economic factors, technology and the future of alternative fuels.

Tickets:
Member: £85.00 + VAT
Non-Member: £120.00 + VAT

Speakers include:

- Martin Fry, Director, Martin Fry and Associates
- Chris Skrebowski, Editor, *Petroleum Review*
- Roger Bentley, Senior Research Fellow, Department of Cybernetics, The University of Reading
- Francis Harper, BP
- Professor Peter Odell, Professor Emeritus of International Energy Studies, Erasmus University
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Subsea solutions

It is now more than 20 years since Shell UK Expro launched the Underwater Manifold Centre (UMC) into the waters of the North Sea and subsea into the offshore psyche by installing this landmark system on the Central Cormorant field. *Steve Sasanow looks at how subsea technology has moved on in the following two decades.**

The UMC is often referred to as the 'genesis' of subsea technology. There were subsea production systems before it, but the first use of several specific technologies – for example, multiplexed electro-hydraulic control systems and remote flowline connections – presaged what was going to become standard practice in the years ahead. In addition, the philosophy and thinking of Shell and Esso behind the plan to deploy the UMC – that is, this is a technology that is going to be important for future offshore developments, so let's test it now – is what set the stage for many developments that have occurred in the following two decades.

And much has happened over the last 20 years. Basic subsea technology is now accepted as proven and reliable to the point that it no longer has to go through extended trials before deployment. Standard factory acceptance testing (FAT) and systems integration testing (SIT) are now regarded as sufficient for equipment bought for conventional developments.

Today, the view of subsea equipment has totally altered. Where it was once seen as the purview of specialist engineers and technologists, it is now accepted as a commodity, hardly different from any piece of topside equipment. Equally, this technology, which was considered only available to big operators with lots of engineering capability, is now open to even the smallest oil company. While Shell, BP and Total have it in their development toolboxes for the ultra-deepwater sectors of West Africa, Brazil and the Gulf of Mexico, so, also, do Venture Production for the North Sea, Reliance Industries off the coast of India, Pioneer Natural Resources for the Gulf of Mexico and Noble Energy off the coast of Ecuador.

Level of confidence

What is significant about the growth in the use of subsea-completed wells is the confidence level that most major operators now have in this technology. There cannot be many, if any, asset managers who would question using subsea systems to produce anywhere in the world. With the decline in production in the North Sea and with significant portions of prospective onshore locations continuing to be off-limits for various geopolitical reasons – ie acreage controlled by national oil companies or in risky environments – the deepwater plays are the key new production areas for the majors and subsea is an essential tool in every sector of the world.

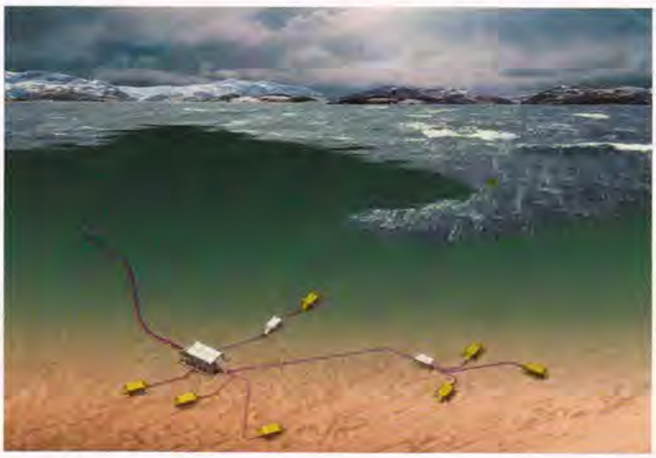
A recently released study by analyst Wood Mackenzie and geological specialist Fugro Robertson revealed that deepwater exploration is responsible for the majority of newly found oil reserves in the last two years. The study put deepwater reserves at 180bn boe, with 114bn boe of this being oil and with each deepwater well adding around 50mn boe of reserves.

The obviously important sectors for development are the US Gulf of Mexico, Brazil and West Africa. The latter sector now includes not just the important Nigerian and Angolan provinces, but also Equatorial Guinea, the Congo, Mauritania and the Ivory Coast. The next big sector is expected to be the Mexican portion of the Gulf of Mexico, where this report has suggested 40bn boe of reserves, or more than 20% of the total projected reserves, are expected to be found. Subsea has already proven to be the key technology for unlocking the reserves in all of these offshore sectors.

The 'super-majors' – BP, ChevronTexaco, ExxonMobil, Shell and Total – have all, to varying degrees, hitched their future earnings and production wagons to subsea, although each has opted for a range of development options at its deepwater projects.

Development options

Shell was the first proponent of deepwater tension leg platforms (TLPs) in the Gulf of Mexico in the 1990s, but the last was installed three years ago at Brutus and the company has increasingly chosen to depend on subsea. It used subsea at the Mensa field, where the combination of long-distance (109 km) and deepwater (1,645 metres) back in the mid-1990s



Statoil's Snøhvit project has a subsea-to-beach development feeding an LNG plant made it a landmark project.

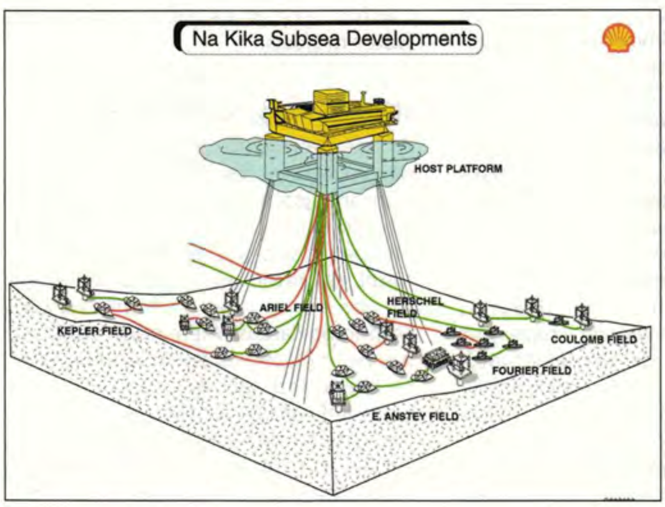
Shell's latest big Gulf of Mexico development, Na Kika, is based around a semi-submersible production floater handling fluids from six different fields – Fourier, Herschel, East Anstey, Ariel, Kepler and Coulomb – which individually would not have been big enough to develop. The latter field, Coulomb, has only just come onstream and is the deepest producing field in the world at 2,316 metres water depth.

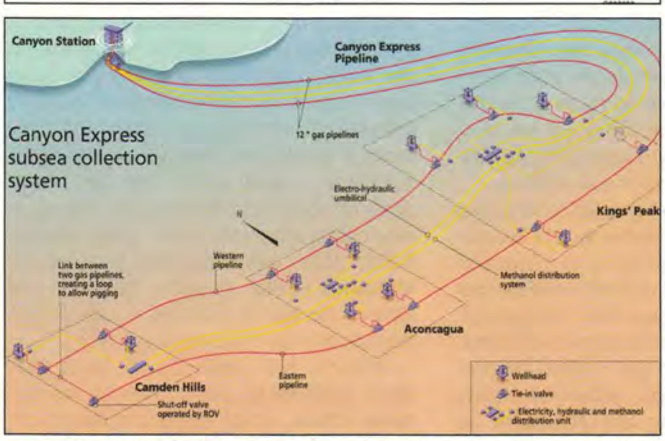
Across the Atlantic, Shell is using a subsea solution at Bonga, offshore Nigeria, although there it is in conjunction with an FPSO. There is another nearby find – Bonga SW – that may be bigger than Bonga, particularly now that Chevron Texaco's Aparo discovery may be an extension of Bonga SW. It is reported that a joint Bonga SW/Aparo development is being evaluated as a standalone development. However, it is likely that subsea will play a part.

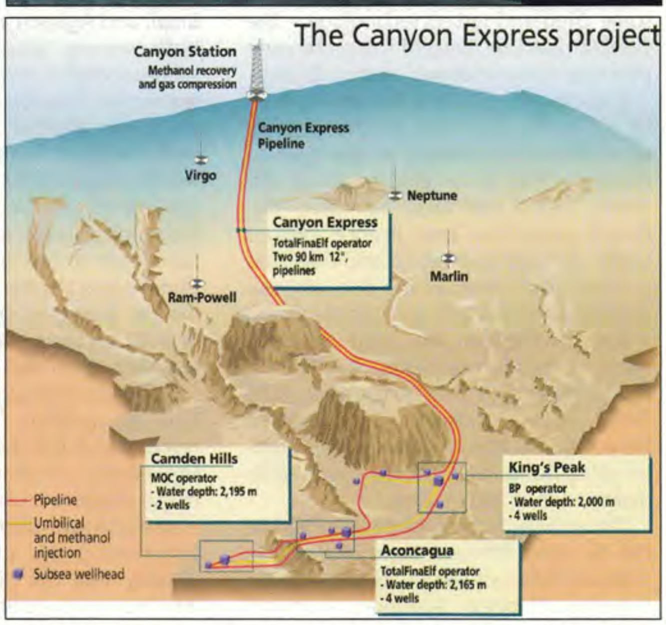
The Troll pilot – the first full-scale subsea processing system – will be joined in the next few years by a separation and water injection system on the Tordis field

Total – or rather its now absorbed merger partner Elf – has had a long history of involvement with subsea going back to work in the 1970s and 1980s in Gabon, the Ivory Coast and Norway, where it developed the Skuld and Super-Skuld concepts. So, it was no suprise that, when confronted with deepwater challenges in the Gulf of Mexico and West Africa, it looked to subsea to solve its problems.

Elf had a history of West African developments, including the Congo. So its enthusiasm about Angola was fully expected when acreage became avail-







Top left: Shell's Na Kika project in the Gulf of Mexico is based around a large semi-submersible production floater handling fluids from six different fields
Top right: Another subsea-to-beach scenario is being used by Norsk Hydro at Ormen Lange in Norway
Bottom left/right: The Canyon Express project, which involves the development of the Camden Hills, King's Peak and Aconcagua fields – combines a long tie-back and deepwater

Subsea UK

To put into focus the growing importance of subsea, the UK's Department of Trade & Industry has spent the last year putting into place a new organisation to promote the UK's subsea expertise, which the DTI sees as key to future offshore exports.

After a protracted search, David Pridden was named as Chief Executive of Subsea UK. Pridden is a subsea and offshore veteran who has been involved in the UK sector for more than 25 years. He started his career with Vickers Offshore, spent time with BP and Kongsberg Subsea Developments, before setting up his own consultancy Mentor Engineering Consultants. After selling his company to McDermott and spending a few years working for several big American offshore companies, Pridden left the sector to head up Manchester-based corrosion specialist CAPCIS, transforming it into a holding company with considerable involvement in renewable energy.

able there. The company made the first major deepwater finds in block 17 – the 'flower' block – which have led to developments at Girassol (sunflower), now in its second year of production, Jasmin and Dalia, with more to come at Rosa/Lirio.

Girassol is an excellent example of the advantages of subsea. Its main reservoir is wide and shallow, making it impossible for a central drilling facility to reach its furthest extent. Only a network of subsea wells spreading for tens of kilometres in either direction from a centrally located production ship would allow all of the reserves to be accessed. A similar scheme is being used at Dalia, although there Total is going back to some tried-and-tested technology – the flexible riser – in place of the more complex riser tower that was used at Girassol.

Even before Girassol, Total/Elf looked to subsea to solve one of the trickiest development problems in the Gulf of Mexico – that is, developing three different fields operated by three different operators and licence groups under a single banner. In addition, this project would feature the deepest producing wells in the world at that time.

Canyon Express, the joint development of the Camden Hills (Marathon), King's Peak (BP) and Aconcagua (Elf) fields, is a significant development because, like Mensa before it, it combined a long tie-back (90 km) with deepwater (2,200 metres).

Meanwhile, ExxonMobil has spread its risk by using different types of developments in different arenas. Its big Angolan complex, dubbed Kizomba, is based around a pair of tension leg wellhead platforms producing to an FPSO, but supported by a large-scale subsea water injection programme around the flanks of the reservoir. Further north in Nigerian waters at Erha, it has opted for the more classic subsea-plus-FPSO style development.

ChevronTexaco, not normally considered a big user of subsea, is looking more to this development technology. It went for an FPSO-with-subsea development at Kuito, Angola's first development outside conventional water depths. Although ChevronTexaco has opted for a compliant piled tower at the 1,250 metre water depth location for Benguela/Belize, the second phase of this project – Lobito and Tampoco – will be developed with subsea wells.

Further afield, two projects where Texaco had considered dry completion units at deepwater locations – Frade in Brazil and Agbami in Nigeria – have now both swung towards the FPSO-and-subsea scenario. Around the other side of the world, ChevronTexaco is moving forward with another long-distance gas tieback project – Gorgon – which will see the development of the largest untapped gas reservoir in Australian waters. Although there is a deepwater element here, most of the reserves are in conventional water depths of no more than 200 metres. However, the field will be tied back 70 km to an island processing facility and then to an LNG terminal onshore.

The growing importance of natural gas and geographic disparity between reserves and demand has led to a spate of LNG projects, several of which will be fed by gas produced subsea. Shell first considered it at Kudu, offshore Namibia, before abandoning the project, while Statoil already has the first subsea-to-beach development feeding an LNG plant at Snøhvit. Although the project is already suffering from problems, they have nothing to do with the subsea system. It is a tribute to the confidence level and reliability of the subsea technology that it is expected to be able to produce on a 98% plus availability basis to keep LNG throughput on a steady level.

Looking for reliability

Not every one of the big companies, though, has exhibited such confidence in subsea technology. BP, for example, knew that it was going to need subsea for big projects in the Gulf of Mexico (Thunder Horse and Atlantis) and West Africa (Greater Plutonio), but was concerned about the reliability of the newer subsea systems being developed for use in deep waters. As so much production – for example, up to 50,000 b/d per well at Thunder Horse – is on the line, BP wanted to ensure that this new equipment was going to be as reliable as that which has been used in shallower water.

As a result, BP, working along with several reliability specialists at Cranfield University in the UK, spent considerable sums of money to develop new ways to measure and evaluate the reliability of equipment that had never been used. Whether this methodology will be adopted by other operators remains to be seen, but it has certainly given BP a comfort zone on its billion dollar deepwater projects.

Increasing demands

As developments move into ever-deeper waters, the cost of floating production systems and their associated equipment, most notably riser and offloading systems, are escalating. As a result, operators are looking for subsea to do even more than before. Technology areas where much emphasis has been placed relate to long-distance tie-backs and seabed processing. And what links these technologies are control systems and data acquisition.

Ever since Norsk Hydro undertook the TOGI development in the early 1990s and extended the envelope of control systems operations out to nearly the 50 km mark, operators and analysts have been drawing circles around existing infrastructure trying to determine how long it would be possible to use their facilities – and push the decommisioning costs into the future – by processing production from new smaller fields. Then came the subsea-to-beach scenarios – like Gorgon, Snøhvit and Ormen Lange in Norway – which put new demands on control systems.

What it has come down to is that there appears to be no limit to the distance under which control systems can operate. Snøhvit will set the standard at 160 km when it comes onstream in 2006, but this falls far short of what is being talked about. Russian operator Gazprom is expecting to take Norsk Hydro and its wide experience with long-distance tie-backs as a partner on its massive Shtokman gas project in the Arctic. Norsk Hydro's specialists took a look at the obstacles to producing Shtokman's very dry gas 500 km back to shore and saw no technology problems. This will create a whole new category of developments to match ultra-deepwater, that is the ultra-long distance tie-back.

However, there are other challenges in the deepwater and Shell, for one, has decided it has the answer – subsea processing – now used as an umbrella term that covers subsea separation, boosting and compression. Shell has been working closely with British engineering company Alpha Thames to qualify its AlphaPrime concept and some of its components.

Alpha Thames is not the only company which has been developing subsea processing – ABB, Aker Kvaerner, Framo, FMC, Twister, GE Oil & Gas, Siemens etc, have all been working on some form of subsea wellstream enhancement. However, the AlphaPrime concept offers Shell and others something very specific – flexibility. A common difficulty for project teams is to convince asset managers to spend more capital than is required on a development in order to build in capability for the future. This is exactly what Alpha Thames' concept, based on a passive manifold, does. It creates the framework on which a variety of configurations can be achieved, but at minimal upfront cost.

Shell has not been shy about its view of the value of this technology. A senior executive from Shell Technology Ventures put forward numbers to suggest how much extra production it might achieve by using subsea processing on just three deepwater developments. The *raison d'etre* at each of the prospects is different. At one ultra-deepwater site it might be the difference between producing and not producing due to the water depth (2,500 metres), while at another heavy oil presents lifting problems in 1,850 metres, while at the third, subsea processing might alleviate topside processing constraints.

In all, Shell has suggested that it might achieve at additional 215mn barrels of production – or $7.5bn of extra income at current oil prices – from the Great White (Gulf of Mexico), BC-10 (Brazil) and Bonga SW (Nigeria) projects. In addition, it also makes mention of the potential of long-term cost-savings of $500mn at Ormen Lange, where it is a partner, by using subsea compression rather than a floating compression platform in the the second phase of development around 2016.

BP and ChevronTexaco have also been looking at subsea processing as part of a consortium including ABB and Aker Kvaerner. But while others still mull plans for putting some form of seabed processing into operation, the Norwegians are moving ahead with real plans.

While the only first full-scale subsea processing system is Troll Pilot, part of Norsk Hydro's development of the Troll West oil province, it should be joined in the next few years by a separation and water injection system at Statoil's Tordis field. Like Troll Pilot, this system will primarily be aimed at removing excess water from the wellstream to reduce processing pressure on the topside at its host facility at Gullfaks C.

In comparison, though, this will be a massive system. Troll Pilot can handle a maximum of 37,000 b/d of water for reinjection, while the proposed system at Tordis will handle 200,000 b/d of gross fluids and be able to reinject 150,000 b/d of water.

As has happened many times in the past, the Norwegians will be out in front deploying subsea technology ahead of the crowd.

**Steve Sasanow is Editor of the offshore technology newsletter* Subsea Engineering News.

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UKCS need for innovative solutions

The installation of the BP-operated Clair platform this summer was an important milestone in the history of the UK Continental Shelf (UKCS) – not just because this is the first fixed platform to the west of Shetlands, but also because the project has overcome a number of tough economic and technical challenges. *Jeff Crook* takes a closer look at Clair and other UKCS prospects, and outlines how the UK will meet demand when it becomes a net importer of gas after 2010.

The Clair field is one of the largest fields in the UKCS. BP estimates that total volumes of oil in place are in excess of 410mn tonnes of 22°–23° API oil, contained within an extensively layered and fractured sandstone reservoir. The field is divided into nine fault-bounded segments, with a common water free level and maximum oil column of 600 metres. A gas cap is present in the structurally elevated ridge segments.

The field was discovered in 1977, but the ten appraisal wells drilled in the 1980s flowed oil at modest rates and provided little confidence in long-term reservoir deliverability. The field extends into four licence areas, which were pooled in 1990 to help gain a better understanding of the reservoir. It was only with 3D survey, further appraisal and an extended well test in 1996, using more advanced technology, that the partners came to the conclusion that the field could be economically developed via high angle and horizontal wells combined with artificial lift.

Field partners are BP (operator, 28.6%), ConocoPhillips (24%), ChevronTexaco (19.4%), Enterprise (Shell) (18.7%) and Amerada Hess (9.3%).

Phase I of the development aims to recover 250mn boe from the central area of the field at a cost of £650mn. Production is expected to plateau at 60,000 b/d of oil and 15mn cf/d of gas. Oil will be exported by pipeline to the Sullom Voe terminal. Associated gas may be re-injected or transported by a pipe spur to the Magnus enhanced oil recovery pipeline, the western section of which runs from the floating production facilities in the Schiehallion and Foinaven fields to Sullom Voe.

The 11,000-tonne integrated deck for Clair's four-legged steel platform (pictured above and on the next page) was loaded out from Amec's Wallsend fabrication yard towards the end of June (see *Petroleum Review*, July 2004) and was said to be 'the heaviest object ever to have been moved on wheels on land'. After being towed to the field site, the deck was lifted into place by the *Saipem 7000* heavy lift vessel (as shown on the front cover). Offshore installation of the 4,500-tonne drilling module, which was fabricated at Heerema's Hartlepool yard, and the living quarters, were completed in mid-July. Amec is undertaking the platform hook-up under a £10mn contract, with start-up later in the year.

It is planned to drill 15 producing

wells, eight water injectors and one drill cuttings reinjection well for Phase I development of Clair. One important environmental protection measure is to inject all produced water and drill cuttings back into the reservoir. Dependent on the success of Phase 1, further phases may follow – possibly yielding a further 400mn barrels of oil from the surrounding areas.

Deep, high-pressure fields

Clair was the largest undeveloped field prior to its go-ahead. However, there are still considerable reserves awaiting development in the UKCS, with fields delayed because of technical challenges. Some of these fields have very deep reservoirs, with downhole pressures of more than 10,000 psi combined with high temperatures and impurities, such as carbon dioxide (CO_2). Drilling a deep well is a time consuming, and costly process, requiring a high-specification rig and 15,000 psi-rated pressure components.

Some of the largest high pressure/high temperature fields (HP/HT), as such Elgin/Franklin and Shearwater, have been developed by means of fixed production platforms. However, these fields are at the cutting edge of offshore technology and teething problems have been experienced, most notably on Shearwater where a lengthy shutdown and costly remedial action were needed to resolve a well problem. As a result, operators have been very cautious about tackling smaller-scale high-pressure fields – until recently.

The Rhum field was regarded as a tough challenge when it was discovered in the 1970s, with its high pressure (12,000 psi) and temperature (150°C) and relatively high CO_2 content reservoir. Although pressures were not as high as Shearwater (14,500 psi) or Elgin/Franklin (15,950 psi), development was complicated because the field was insufficiently large to justify a production platform, since it was located in fairly deep water (350 ft) in a remote location 380 km north-east of Aberdeen. It was, nevertheless, a significant find by North Sea standards – holding 1.1tn cf of gas in place, of which 800bn cf of gas is considered recoverable.

However, with new thinking and experience from other projects, BP (operator; 50%) and its partner Iranian Oil Company UK (50%) came to the conclusion that a subsea development was viable, and gave the go-ahead for a long tie-back to the Bruce facilities. The project was granted DTI approval in May 2003. It is due onstream in October 2005, with plateau production of 300mn cf/d of gas and a field life of around 16 years.

Project cost is around £350mn.

A subsea manifold will gather the flow from three subsea wells with the products transported 44 km by a pipe-in-pipe flowline to Bruce. A caisson riser will be installed on the Bruce compression reception centre (CR) platform as part of the overall project, together with a 1,700-tonne compression module, fabricated at Amec's facility in Wallsend.

A high-integrity pressure protection system (HIPPS) will be installed on the manifold to ensure that the flowline is not subject to over-pressure from full well shut-in pressure. This style of ultra-reliable shut-down system was introduced towards the end of the 1990s, to enable the wall thickness of production pipelines to be reduced without compromising safety, thereby helping to contain costs.

UKCS prospects

There also remain some large and relatively straightforward finds in the UKCS, particularly in the Moray Firth, where the Buzzard field was the largest discovery for a decade when it was found in June 2000. The field lies quite close to the marginal Goldeneye gas-condensate field, which contains 500mn cf of gas and 17mn barrels of condensate. Goldeneye is being developed by a Shell-led consortium via a normally unmanned platform connected by a 105-km wet-gas tie-back to St Fergus.

The EnCana-operated Buzzard field could yield over 400mn barrels of oil. First oil is slated for 2006, with production expected to reach a plateau of 180,000 b/d to 190,000 b/d in 2007. The £1.35bn ($2bn) project consists of three bridge-linked steel platforms in about 100 metres of water, together with two subsea water injection manifolds. Crude oil will be transported to the mainland via a pipeline tie-in to the nearby Forties pipeline system, while the natural gas will flow to market via the Frigg pipeline system. Buzzard will provide a potential transportation hub for other finds in the Moray Firth.

However, aside from this project UKCS activity is subdued. Buzzard is equivalent to around one-third of the UK offshore industry's total annual expenditure, which is currently running at around £4bn this year. Current spending is slightly ahead of PILOT's* 2010 target for sustained capital investment of £3bn/y, according to figures in its annual report for 2003, published this June.

Discussing UKCS prospects in an introduction to this report, Stephen Timms, Minister for Energy and Chair of PILOT, said: 'While the current level of capital investment in the UKCS is expected to remain strong, forecasts suggest that meeting PILOT's 2010 production target of 3mn boe/d is becoming more challenging. We need to work quickly to influence this. Production costs are rising and exploration is at an all time low.'

'We've dealt with some tough challenges in the past. But it will only be by continuing to work together through PILOT, with an increased collective sense of urgency, that government and industry can overcome the barriers to further activity and find the innovative solutions that will help unlock the UK's remaining economic reserves.'

UK gas imports

With UKCS production in decline, it is now recognised that the UK is rapidly moving from a net exporter to a net importer of natural gas. The consensus view, as expressed in a recent UK House of Lord's (HoL) European Union

continued on p29...

Growth through exploration and acquisition

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

UK-based independent oil and gas E&P company Paladin Resources is currently exploring in six countries worldwide – in the UK, Norwegian and Danish sectors of the North Sea, Indonesia, Tunisia and Romania. New business activities are ongoing to identify and access new opportunities in the North Sea and in new countries, particularly in North and West Africa, as well as southeast Asia. (See **Figure 1**.)

A 44% increase in production, combined with continuing high commodity prices, led to operating cash flow of £143.1mn in 2003 (2002: £96.3mn) and profit before tax of £84.8mn (2002: £66mn). Profit for the year was £30.4mn before an exploration write-off of £2mn in respect of unsuccessful exploration costs relating to the Group's Romanian interests, giving a net profit of £28.4mn (2002: £20.1mn) – a rise of 41%.

Net production for the year totalled 14.5mn barrels of oil and NGLs, and 4.9bn cf of gas, giving a combined average of 42,006 boe/d – a new record for Paladin and representing an increase of 44% from 29,117 boe/d in 2002. Overall, the Group invested £59.8mn (2002: £26.4mn) on production and development projects, of which £24.6mn was invested in the UK, £22.7mn in Norway, £7.6mn in Denmark, £4.4mn in Indonesia and £500,000 in Tunisia.

Paladin also invested £9.8mn on its exploration activities in the UK, Norway, Denmark, Indonesia, Romania and Tunisia during the year (2002: £3.6mn), with exploration drilling success in both Denmark and Tunisia. Good progress was also made during 2003 in expanding the Group's portfolio of exploration interests, particularly in the UK and Norway, where successful applications were made for a number of blocks in licensing rounds.

Proven and probable reserves (on an entitlement basis) at 31 December 2003 were 132.7mn boe, has compared to 108.2mn boe at 31 December 2002 – a 23% increase. Net positive revisions of 3.5mn boe replaced 23% of production in the year, while acquisitions in the UK added a further 37.5mn boe to the Group's reserve base. Oil and gas reserves constitute 87% and 13%, respectively, of the overall reserve base. On a working interest basis, Paladin's reserves increased to 150.9mn boe (2002: 127.6mn boe).

Strategy and outlook

Paladin's strategy is to grow through both exploration and acquisitions, in particular from oil majors selling off non-core assets in maturing provinces such as the North Sea. The company has already had exploration drilling successes in Tunisia and Denmark and 2004 will see further increases in exploration activity, with the Group participating in up to eight exploration wells.

Early in 2003, Paladin set new targets for continued growth – namely to increase production and reserves to 100,000 boe/d and 250mn boe, respectively, by 2008 through a combination of organic growth from the existing portfolio of assets and further acquisitions. In 2004, the Group has a substantial capital investment programme of some £75mn planned, which, it is anticipated, will result in an increase of around 10% in Paladin's production compared to last year.

Recent exploration success

In July, Paladin announced the discovery and successful testing of oil in Dalia 1, the latest exploration well in the Adam concession in southern Tunisia. The well, operated by Eni Tunisia, was spudded on 20 May 2004 and encountered several oil and gas bearing zones distributed throughout the Acacus A and Tannezuft sandstones at a depth of approximately 3,400

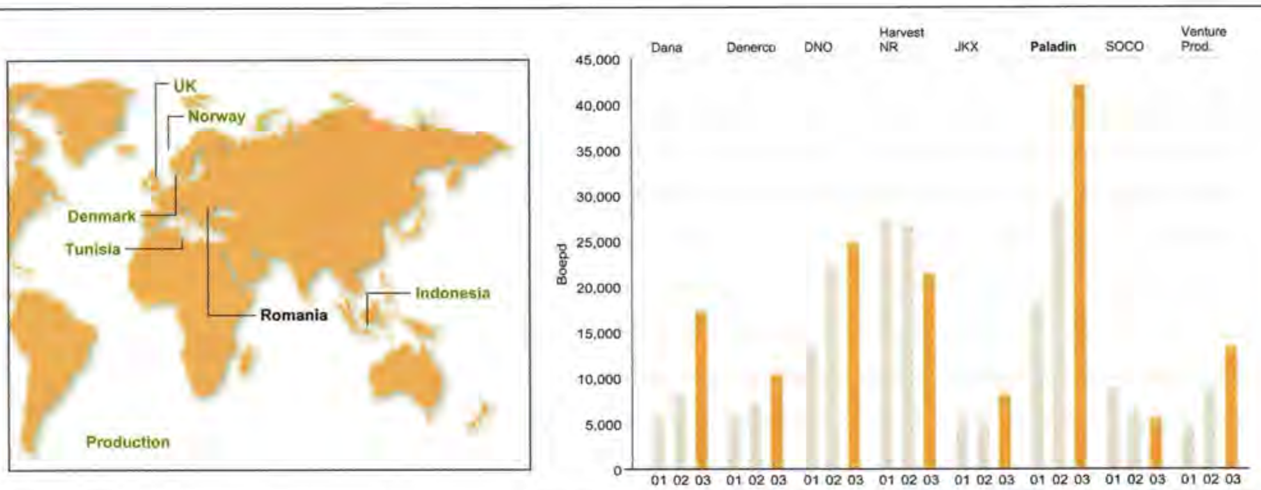

Figure 1: a) Paladin's international E&P activity b) Company production comparisons, 2001–2003 (in boe/d)

metres. During the initial testing of selected oil-bearing intervals across 11 metres of perforations, the well produced at a rate of approximately 3,600 b/d of 44° API oil on a 48/64-inch choke and at a flowing wellhead pressure of 1,150 psi. The well has been completed and suspended as a production well pending approval of a field development plan and hook-up to existing process and export facilities some 13 km distant.

An oil discovery from a well on the Paladin-operated Brechin prospect in UK North Sea block 22/23 was announced in June. Located 3.5 km to the east of the Arkwright field and within the greater MonArb area, the 22/23a-7 well was drilled to a depth of 9,150 ft and penetrated an oil column of at least 110 ft. The discovery will be developed as a subsea tie-back to the Arkwright template as early as possible.

Brechin follows on from a successful appraisal well in North West Montrose recently announced by Paladin. The exploration potential in the MonArb area is further underpinned by the Brechin well success, and in particular the risk on the nearby Forfar prospect is now greatly reduced, reports the company.

Earlier in the year, in May, Norsk Hydro, operator for the Brage field in production license 053B in block 31/4 offshore Norway – in which Paladin holds a 20% stake – announced it had proven a new, minor oil zone that lies at a deeper stratigraphic level than the main field reservoirs. The discovery is in a sandstone formation of Jurassic (Brent/Ness sandstone) age, although the reservoir is either filled with water or has disintegrated in other places where it has been tested on the Brage field. The oil was found during the drilling of well 31/4-A-30b. The purpose of the drilling activity was to secure stratigraphic control, and preliminary calculations initially showed a little less than 1mn cm of oil. There is a potential for a further increase in the volume, depending on the size of the reservoir. The discovery thus represents an interesting additional resource that can quickly be tied in to production.

Also in May, Paladin announced the completion of the drilling of well 22/17-2 – its first operated well in the UK sector of the North Sea – using the *GSF 140* semi-submersible rig. The well has proved up a significant extension of the Montrose field to the northwest.

*Visit **www.oilvoice.com** to view over 300 continually updated oil company profiles, or contact Chris Pettit at e: **chris@oilvoice.com**

...continued from p27

Committee report, is that by 2010 the UK will be importing around 50% of its gas requirements, and that this is likely to rise to around 70% by 2020.

Several major gas import projects are underway or under consideration in order to deal with this situation. Most notable are the supply of gas from Norway's Orman Lange field, which will provide 20% of UK gas needs from 2006/2007; a second interconnector pipeline, linking Balgzand to Bacton; and three LNG import terminals. However, these projects will take some time to come onstream and this has raised fears about the security of UK gas supplies over the next couple of winters.

After investigating security of supply both in the short and long term, the HoL Committee concluded that: 'In the short-term, we are uneasy about the position in the UK over the next two to three winters where the supply and demand balance is already tight. The Minister sought to reassure the Committee, but we remain unconvinced. We note that Ofgem believes the supplies are adequate except in extreme conditions. It is the extreme conditions we worry about.'

In the longer-term, new LNG import terminals (see *Petroleum Review*, July 2003) and new gas storage sites will greatly enhance the security of supply. Work is progressing to develop an LNG import terminal at the existing Isle of Grain LNG storage site in the Medway River, 20 miles east of London, and a further two LNG import terminals are planned for Milford Haven, in south-west Wales.

LNG import terminal update

A joint venture between BP and Sonatrach has announced that it plans to supply the Isle of Grain terminal with enough LNG, from 2005, to provide 500mn cf of natural gas to the UK market. The gas would be sourced from Algeria and potentially represents 5% of UK demand.

The proposed South Hook LNG terminal at Milford Haven will have an output of 10.5bn cm/y. It is a joint venture between Qatar Petroleum and ExxonMobil and will most probably be supplied from the Qatar II facility in Qatar. The second proposed plant at Milford Haven, called Dragon Gas, will have an output of 16.5mn cm/d. Petroplus, the original developer of this project, was joined by co-venturers Petronas and the BG Group towards the end of 2003, both of whom have their own sources of LNG.

In the meantime, Transco is currently undertaking preparation work for a 128-km gas pipeline to link the proposed LNG import terminals at Milford Haven with the national transmission system at Aberdulais, just north of Swansea. Feasibility studies into possible routes were completed in 2003, and currently all parties are working towards a project completion date of October 2007.

Gas storage sites

The security of national gas supply will also be boosted in the longer term by construction of additional gas storage sites. These will supplement the Rough offshore storage facility (which used the depleted Rough field in the southern North Sea), several LNG storage sites built in the 1970s and 1980s by British Gas, and the Hornsea salt cavity facility.

The most advanced of the new storage sites is at Aldbrough, located 1.5-km inland from the Humber coast. This site will have nine cavities with a total storage capacity of 420mn cm of gas. Construction involves drilling a directional well from a central processing area into salt strata; seawater is then pumped down the borehole to leach out a storage cavity. The facility is a joint venture between Scottish and Southern Energy and Statoil – the same joint venture which operates the nearby Hornsea site. First turf was cut in a ceremony during March 2004, but leaching is a lengthy process so operations are not due to start until 2007. The site will be connected by an 8-km pipeline to the national transmission system at Sproatley.

Another 280mn cm capacity facility is to be built at Humbly Grove in Hampshire, for operation by Star Energy. The site is an existing onshore oil field. Amec was awarded a £50mn contract for this project in June 2004, with its work including construction of a 27-km gas pipeline from Humbly Grove to Barton Stacey, where it will connect with the national transmission system.

Star Energy is also in the pre-planning stage for a 420mn cm facility at Welton, in Lincolnshire, while Scottish Power is presenting evidence to a public inquiry for a 170mn cm facility at Byley, in Cheshire. Meanwhile, a proposal for a 5bn cm storage site in Lancashire is at the pre-planning stage by Cantaxx.

**PILOT is a joint UK government/industry 'think tank' established in 2000, the aim of which is to improve North Sea competitiveness and maintain the UK as a pre-eminent centre for oil and gas production.*

Photos courtey of Amec

Overcoming the innovation barriers

The onshore pipeline construction industry has seen no radical innovation in the last 30 to 40 years. Basically, onshore pipelines are constructed in much the same fashion, using much the same equipment, as they were a generation ago. So, why has the onshore industry been unable to make the sort of leaps in technology that have driven the offshore construction sector? Here, *Nick Lowes* and *Jan Paul van Driel* of SDG*, together with BP's *Graham Freeth*, explore the barriers to innovation and unveil systemic challenges which will take a combined effort by all parts of the industry to overcome. The good news is that just such an effort has recently been initiated, with encouraging early results.

Innovation is fundamental to long-term business success. Many of the world's leading organisations have continued to grow by constantly re-inventing their products, their business and even their industry. Within the oil and gas industry innovation in subsurface and drilling technologies have halved well costs over the last 10 years. In offshore construction the technological leaps of the 1970s and 1980s saw the installation of ever larger structures in ever deeper water. In parallel, new and improved pipeline installation concepts such as reeling, J-lay, and towed bundles provided access to deeper waters at lower cost. Vast amounts were spent on developing these technologies, and huge commercial bets were made by oil companies, contractors and suppliers.

By comparison the onshore industry looks like an innovation desert (see **Figure 1**). The last major onshore pipeline construction technology advances were the introduction of hydraulic excavators in the 1960s and automatic welding in the 1970s. Despite these new technologies, pipelines are still built in the same basic way – individual 40-ft pipe lengths are transported by truck and laid along the side of a ditch, welded together and lifted into the ditch using sidebooms. There is no doubt that these tried and trusted methods have served the industry well over the years, but there's a growing recognition that new technologies must now provide better approaches. And yet we don't see them.

To understand the barriers to innovation we need to look at how the onshore pipeline industry is structured, and the perceptions and attitudes of the various industry players including:

- clients – upstream oil and gas companies, pipeline operating companies,
- engineering design consultants,
- construction contractors,
- equipment suppliers, either OEMs or leasing/hire companies, and
- regulatory authorities.

Each group plays its part in a system that has hampered innovation and risk-taking (**Figure 2**).

Operators stifle innovation

The oil companies were at the forefront of driving the technological innovations in the offshore industry over the last two to three decades, through both in-house R&D programmes and funding of external industry initiatives. Why haven't we seen the same impacts onshore?

Firstly, expediency. Tapping the riches of the deep offshore *required* new technologies. Onshore is a more forgiving technical environment, despite the logistical, legal and environmental complexities, and innovation has not been essential for project execution.

Secondly, operators have over the years developed a *master-servant* mentality towards construction contractors. Contracts are usually awarded on a lowest cost basis (often forced through tender rules), reflecting a 'zero sum' commercial mindset – I lose if you win. This commoditises contractor services, squeezes contractor profit margins and provides little incentive or opportunity for re-investment in new technologies.

Furthermore, when a contractor does submit a differentiating solution an operator might re-tender on this basis, or at least specify the same smart solution for their next project. So readily transferable innovation (not backed by unique resources or legal protection) only benefits the innovator once, at best,and then re-sets the baseline for the industry. This is less the case offshore, where consolidation in the contracting sector and unique ownership of technologies and resources has given negotiating power to contractors. So, a partnership mentality is more common.

Also, operators are typically risk averse and want proven technology and processes. This is reflected in the designs of their engineering consultants, who have little or no incentive to persuade the industry to pursue possibly more risky avenues. There are good reasons for this – both from a commercial and HSE perspective, with a huge cost of getting it wrong. But how does the industry resolve the resulting 'Catch 22' if the operators can't provide a test bed for new innovations?

Finally, construction is seen as non-core business which provides no opportunity for competitive advantage, so oil companies are less willing to take the lead on innovation than in the past – they prefer to let the (supply-side) market be the driver. To date the market has failed to deliver.

Contractors and suppliers stifle innovation

The contracting industry views the world through a project lens where each project must deliver to the bottom line. But, new technologies or processes can rarely be justified on the basis of one project only – it requires a vision of where they could lead, and a willingness to value the future possibilities they create. If future options are not valued, then R&D dollars are tough to find.

A second major innovation barrier is the high sunk costs in the existing equipment base.[1] Why should a contractor or manufacturer introduce new technologies that destroy the value of its existing assets and competitive basis? Yet the likes of IBM, Sony, and Daimler-Chrysler continuously destroy their existing business through innovation – before a competitor does it first.

Another paradigm in the construction community is that all the benefits of innovation will flow to the operator client, so the risks are not worth taking. This is true where innovation is easily and quickly disseminated, but for radical innovation history tells us something different. The innovator captures most of the value until the new technology becomes broadly commoditised – at which point the customer reaps the lion's share of the gains (**Figure 3**). So, a far bigger risk for an equipment manufacturer or contractor is that a competitor innovates while it stands still.

Finally, contractors are equally, or perhaps more, risk averse than their operator clients. In part, the contracting industry is simply recognising the risk appetite of its customer base. In addition, with relatively weak balance sheets, the downside of innovation risk looms much larger than the upside.

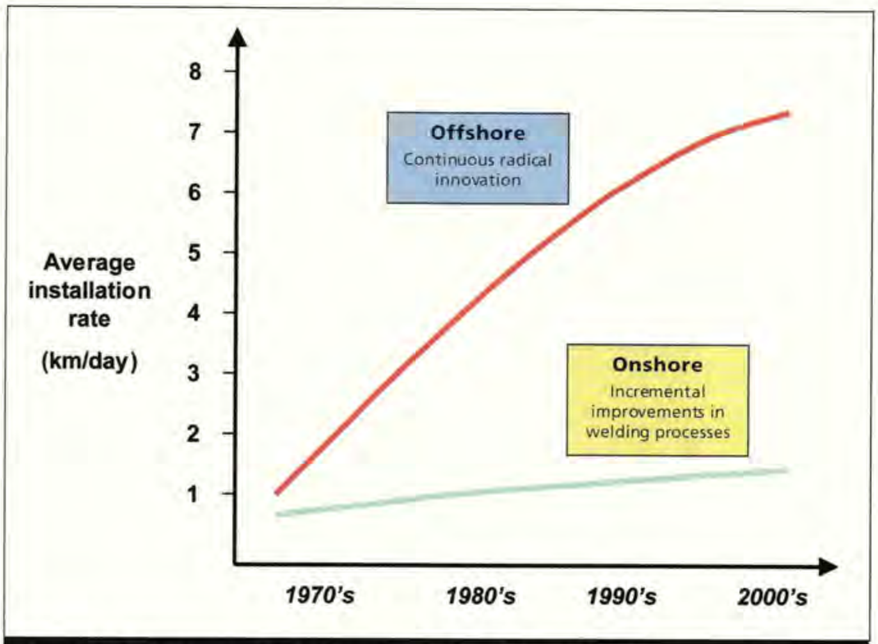

Figure 1: Relative construction performance for large diameter pipelines

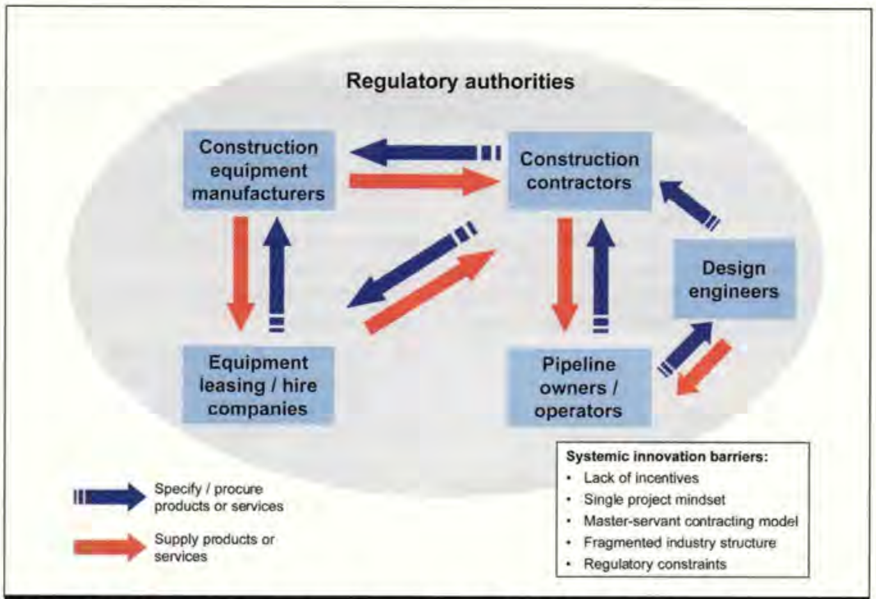

Figure 2: Onshore pipeline construction – a system to stifle innovation?

Regulatory authorities stifle innovation

Regulatory authorities exist to protect the safety of construction crews, the public at large, and the environment. The flip side is they can act as a barrier to new methods. The myriad of codes, standards and guidelines under which the industry operates were written for yesterday's technology, and certifying a new approach is a time-consuming and energy-sapping task. Lack of common international standards multiplies the effort, since innovations may require multiple certificates, or be excluded from some markets. So, change requires a broad-based industry push – not something a single company can, or wants to do.

In some countries regulatory authorities also represent the national commercial interest. Countries are loath to be a test bed for new technology, although keen to reap the benefits once proven. The challenge is most severe where there are favoured local companies whose business could be damaged by the new innovations of foreign competitors.

Interestingly, in other construction sectors, such as tunnelling, the regulatory authorities have been major drivers of innovation. Tighter safety and environmental regulations have caused massive leaps in tunnelling technology in the last two decades that have largely removed operatives from the work face. If authorities demanded similar improvements from the pipeline industry perhaps we could anticipate similar results?

Unleashing innovation

What's the value at stake here? Simply put, it's huge. A conservative estimate is that at least $50bn will be spent on new onshore oil and gas transportation systems over the next 10 years. If we include replacements for old systems, largely in the FSU, the number doubles. Of this, construction costs will represent around $40bn (some 40%) – so a 5% performance improvement, a realistic target, equates to $2bn of value creation.

And pipelines are becoming increasingly important. For many of the new mega-projects, transportation systems will make up 30%–40%+ of the total development cost, and are absolutely

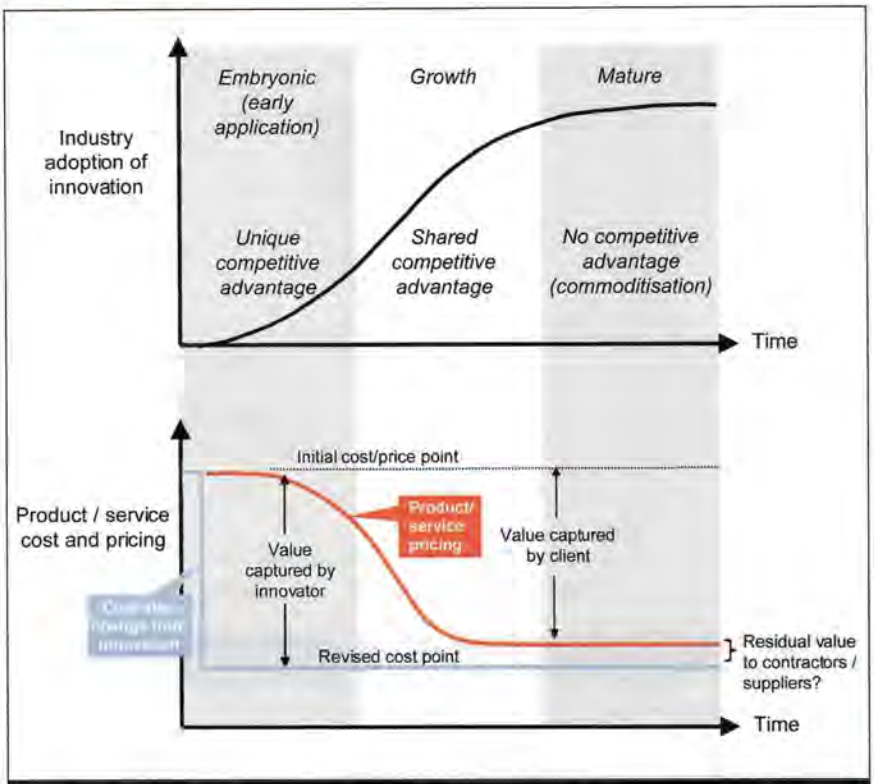

Figure 3: Innovation – who captures the value?

critical to overall project success. The development of huge stranded gas resources in Siberia, the Caspian region and Alaska depends on finding cost-effective pipeline export solutions. So, the pressure to improve performance will be on the industry like never before.

Step in the right direction

Recognising this, BP launched a Pipeline Cost Reduction (PRC) technology project for large diameter onshore pipelines in 1998, and has had notable successes in developing new materials and welding processes. However, the contracting community has remained somewhat suspicious of such an open, collaborative R&D effort and has been reluctant to fully participate[2].

To better engage the contracting community, BP is now working with IPLOCA (the International Pipeline and Offshore Contractors Association) to co-sponsor an industry initiative to boost innovation in onshore pipeline construction. Titled 'New and Novel Construction Methods', the BP-IPLOCA initiative is looking at a wide range of new ideas from incremental to radical, such as land lay barge concepts and airships for on-site materials transportation. An initial workshop in June 2004 was enthusiastically attended by over 30 companies from 25 countries and included operators, contractors, engineers and equipment suppliers. Ideas selected for further funding were chosen by this broad group of participants and so truly represent the views of the industry.

Identified sources of value opportunity include:

- Safety – mostly related to manpower and logistics, with emphasis on driving to and from camps.
- Speed – the pipeline's rate of progress. Traditionally the focus has been on welding performance, but a systems view reveals the critical path activities are elsewhere, and dependent on environmental conditions.
- Cost – direct and indirect. Cost correlates with speed, but costs can also be brought down by smarter camp design, improved logistics, increased automation of the work process etc.
- Surface disturbance – largely caused by movement of people and materials over the right of way. Impacts the environment and adds to rehabilitation costs.
- Routing – new routing alternatives may become available through new technologies, such as use of long-distance directional drilling.

Who will gain from the initiative? Our belief is that innovation benefits the entire industry. As costs come down, activity increases and contractor capacity is more fully utilised. The construction company in the master-servant model can only make money through claims or in times of under-capacity. The more room there is for differentiation through innovation, the more room there is to partner with clients and trade-off client requirement for profit margin.

The key to innovation is rewards – the innovator has the incentive to innovate, and the client to adopt the innovation. In such a model, services become less sensitive to cost and specialists are rewarded for their unique value adding capabilities.

Conclusions

In this article we have explored many innovation barriers, which can be summarised as follows:

- Incentives – no perceived need, project by project mindset, risk aversion.
- Roles – master-servant model, non-differentiated services.
- Industry structure – fragmented, independently-acting players.
- Regulations – often prescriptive rather than goal oriented.

We have argued that removing these blockers to innovation, and turning them into forces for innovation, will require a broad industry effort. So, the BP-IPLOCA initiative is a timely step in the right direction, and there's little doubt the industry will be reaping the benefits a few years from now. And perhaps the onshore pipeline industry, so long the laggard, will become an innovation role model for the rest of the construction sector.

Footnote

1. Traditionally, the UK market has used a plant rental rather than ownership model due to the high variability in work load (no public sector safety net), and the resulting pressure to reduce fixed costs. Contractors in other countries have tended to own, but we are now starting to see a global shift towards rental.
2. 'Pipeline industry R&D cooperation', N sanderson, BP Exploration Operating Company. Keynote lecture to the 14th Biennial Joint Technical Meeting in Pipeline Research, Berlin 2003.

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Keeping projects on time and on budget

***John B Reed*, CEO, Intec Engineering, takes a closer look at EPIC contracting strategies and encourages industry to inject some 'common sense' into the process in order to stop the ballooning budgets and missed delivery dates often associated with such contracts. He urges industry to evaluate the appropriate sharing of risk, recognising who on the project can best 'absorb' risk and who can best 'control' it.**

Einstein defined insanity as 'doing the same thing over and over again and expecting a different result'. That is my view of the current state of EPIC [engineering, procurement, construction and installation] contracting, especially with regard to the large complex projects being pursued without a clear understanding and assignment of risk. It is time for a new approach. It is time to be honest about the damage we're doing to the industry. It is time to inject some common sense into the contracting process for these jobs. And it is time we start working together to deliver on-time projects that fuel the economy rather than leaving a trail of litigious blood-letting.

This article will focus on large projects, of the type commonly seen offshore West Africa. Most often these projects involve an EPIC format and a very large capital expenditure, including a high cost to bid. In addition, these projects are often technically challenging and include some applied R&D and new techniques or products or both. Their complexity and breadth often limit the number of participants to a few truly qualified contractors. They also require significant partners and/or subcontractors to accomplish the full scope of work. The best reason to use these projects for our discussion, however, is the industry's dismal record of performance to date.

Playing by the client's rules

Contractors are always obligated to play by rules set by their clients, who unfortunately cannot always control the rules. And, while the conditioning of the tender can sometimes alter the final contract, in my view, clients and contractors often create the real damage with poor decision-making from the outset. Granted, operators are heavily governed in many cases by their NOC partner's legal framework, especially with regard to competitive bidding – the mandate for it in the face of factors begging to differ. On the client's side of the ledger is its own corporate governance that also can conflict with project goals and expectations for delivery.

The illusion of competitive bidding further constricts the business goal. Execution of a dictated pre-qualification process designed to vet potential bidders on a technical, commercial and financial basis normally incorporates 'fudge factors' to ensure the proverbial three-bidder rule. This circuitous route results because many contractors cannot pass a strict application of the criteria intended to pre-qualify bidders, especially when the pre-qualification includes the absorption of financial consequences of a poor performance. In many cases, a clear choice of a contractor or group exists to produce the business goal; however, decision-makers often disregard this fact in favour of satisfying some tick in a spreadsheet, which is then fudged as stated earlier.

One other very important dynamic in play is the monumental difference in financial strength between client and contractor. This difference goes to the very heart of this argument because, ultimately, the owner suffers as much or more than the contractor. Nonetheless, the contractor suffers with the budget and schedule overruns as well. And both parties take the whip of the financial community in the capital markets. Any candid client project manager would agree because project disappointments – regardless of their origin – are never welcome in the financial world.

Importantly, those who can best control risk are often not those who are capable of absorbing the consequences of that risk. That is, the prevailing industry presumption that shifting risk from the client to the contractor will shield the client from this exposure is unfounded, regardless of legal standing, and does not reflect an understanding of shared challenges in a frontier environment.

Managing the risks

What are the 'different' results in Einstein's insanity definition? Generally, the major West Africa projects to date are all running late and tending toward huge cost overruns. Knowing that risk does not disappear, the general contractual approach for these projects has been to shift risk from the operator to the contractor.

This attempt to 'lessen' operator risk is aggravated by limited accountability within client organisations for the failures on these projects. Clear evidence of this is when the client's project manager moves on before the final rate of return on these projects is known. To make matters worse, contractors often are not capable of absorbing the risk they are willing to take on. However, they may, in fact, be in the best position – either because of their technical knowledge, project management skill or both – to control the risk. Disregard for these nuances in early project planning, however, results in a disconnection between absorb and control.

Both the contractors and the client share in the culpability. In the past, the industry has resolved its project issues by throwing more money at a project. However, recent market conditions combined with too many 'qualified' bidders has resulted in significantly tightened margins. Further, while the prudent contractor may diligently seek protection, pressure to secure market share can lead to inappropriate risk-taking to become the low-bidder and win selection. In reality, nobody wins.

What can be done?

A number of options are available to the project operator.

- Partner with the right contractors. There is, in some cases, only one right choice of a contractor or group. In any case, the contractor must assume an active role to assure all stakeholders that his company has the right capabilities, including a reasonable price.
- Determine a realistic sharing of risk based on real-world dynamics – ie identify and accept who can appropriately absorb risk and who can control it, recognising that 'absorption' and 'control' represent two totally different decision-making criteria. This process is not easily undertaken as it means averting dated legal rules to achieve a successful project and a healthy business environment. As one option, it may be possible to cap the risk of the contractor, who can then focus on understanding and controlling the risks.
- Repeat contracts with same company or group as the track record is clear. For instance, Shell experienced great financial and technical success in this effort in the Gulf of Mexico throughout the 1990s.
- Remunerate contractors at some level for bid preparation. Spending between $1mn and $2mn to bid is not taken lightly by the contractor community, especially in a tight margin situation. This commitment could be an acid test for the client to see who is really capable of tackling the project.

It is also important to assess what type of terms/conditions might be workable.

- Pre-select a contractor, then work together with the client to jointly arrive at a bid. This approach also may require some payment to cover costs.
- Encourage contractors to perform some tasks at near-cost levels as a trade-off in order to not be exposed or to have limited exposure to certain risks.
- Recognise that a failed contract or contractor is not in its interest because it affects returns and market reputation.
- Incentivise only those portions of a contract where the contractor can exercise significant control.
- Work jointly to benchmark risk.
- Do not force early design verification onto the contractor as a method of shifting risk.

Finally, consider the risk of additional cost in focused categories. First, consider risks that should be foreseen by and are largely within the control of the client. Second, consider risks that should be foreseen by and are largely within the control of the contractor. Third, identify those risks that are equally shared and those that are potentially unknown by either party.

This 'map' toward a risk resolution, combined with an appropriate incentive package for a specific project, can help bring the parties closer to an agreeable ability to absorb risk, thereby helping to keep project schedules and costings on track.

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New publication

Hydrocarbon Management (HM 40): Guidelines for the crude oil washing of ships' tanks and the heating of crude oil being transported by sea

2nd edition. Essential reading for ship owners and operators, cargo surveyors, equipment manufacturers, marine terminal managers and all those concerned with the safe and efficient operation of the marine industry and its impact on the environment. Safe handling of crude oil is paramount in the industry. This publication has been compiled with the aim of sharing the experiences of a large number of international oil companies. It provides guidance for the heating and crude oil washing (COW) of many crude oils that may be transported by sea. Companies operating tanker fleets have also contributed to the development of HM40, allowing the data to be reviewed by the marine industry at large. As well as enhancing the current regulations regarding reducing marine pollution, the document is designed to advise the reader on the grades of crude oil that may give rise to an increase in volatile organic compounds (VOC) emissions if excessively used for COW. The document also highlights a number of crude oils that are know to be potentially harmful due to the concentration of benzene and/or hydrogen sulphide. This publication can be downloaded free of charge from the Energy Institute's website **www.energyinst.org.uk** (under 'Technical – Publications to download')

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Talent is key to success

The Energy Institute (EI) awarded the 70th Melchett Medal* to *Sir Roy Gardner* HonFEI, Chief Executive, Centrica. The award was presented at the annual ceremony sponsored by Norman Broadbent's Energy and Natural Resources, on 22 June at the Royal Aeronautical Society, where Sir Roy spoke of Centrica's success story and the challenges of privatisation. The following is an abridged version of his speech. The full version can be found on the EI website at www.energyinst.org.uk

Above: Sir Roy Gardner, Chief Executive, Centrica, speaking at the Melchett Lecture

In his lecture, Sir Roy looked back over the last seven years and spoke of the challenges that Centrica had overcome. 'The first priority was to retain our domestic gas customers in the face of competition... To survive, we had to study our customers and understand how to serve them better – better than we had in the past, and better than the competition. The key was changing the internal mindset so that people would start thinking of customer service not as a cost, but as a source of competitive advantage.'

'To do this, I brought in a new management team to infuse the company with new ideas and energy. We also restructured the bonus scheme so that people were rewarded not only on financial performance, but also on customer satisfaction levels. In short, we worked to create a whole new culture.'

The next generation of employees

He went on to explain that while the team worked to transform Centrica's culture, it also acted decisively to improve its ability to attract, develop and retain the very best talent, identifying and nurturing 'the next generation of employees'. 'We can now spot areas where we are strong, as well as areas where we are underweight in certain skills or experience. With this insight, we then focus our training and recruitment efforts to maximise value for the organisation,' he explained.

Concluding his presentation, Sir Roy commented: 'For the long-term viability of any company, employee development must be a priority. Giving people the opportunity to develop new skills and experiences also increases their marketability both internally and externally... We also have several initiatives under way to address the potential skill shortages in the future. We have established a number of training centres around the country to support our aim of recruiting and training some 5,000 engineers over the next five years – of which about half will be modern apprenticeships. We are also looking to extend the use of government-backed schemes to recruit and train customer service advisors.' *[Ed: Sir Roy chair's the UK Government's task force on modern apprenticeships.]*

A role for the EI

'I am committed to working with other companies – as well as with organisations such as the Energy Institute – to move the agenda forward on this important issue. The way I see it, it is a

three-way win – for young people, employers and ultimately UK plc.'

Responding to Sir Roy's presentation, Louise Kingham, EI Chief Executive, added: 'Organisations like the EI play an important role in addressing this issue by working with educators and employers to ensure – whatever the type of learning – the EI develops people and provides them with the skills that energy industry employers need. At the same time, rewards individuals with much valued professional recognition from student to technician or graduate and on to become tomorrow's energy industry leaders.' ●

Top left: Sir Roy Gardner receives the Melchett Medal from Professor Martin Fry CEng FEI, EI Vice President;
Middle left: Q&A session following Sir Roy's lecture
Bottom left: Sir Roy meets Charles Henderson (middle) FEI and Chairman, Total Holdings UK, and Peter Newman (left), EI Treasurer, and Global Managing Partner, Oil & Gas, Deloitte

All photos: Jim Four

*The Melchett Medal is named after the first President of the the Institute of Energy – now merged to form the Energy Institute, the Rt Hon Sir Alfred Mond, who later became Lord Melchett and Chairman of ICI. The Medal is one of the EI's most prestigious annual awards and is given in recognition of outstanding services to the energy industry.

Professor Martin Fry, CEng FEI, EI Vice President (below right) also awarded Sir Roy with an Honorary Fellowship of the Energy Institute at the lecture (below).

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18 - 20 October, 2004

COURSE VENUE:
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EI MEMBER:
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NON-MEMBER:
£1600.00 (£1880.00 inc VAT)

This intensive, **three-day course** concentrates on economic evaluation techniques applied in upstream and downstream oil and gas projects. It will discuss the fundamental variables and issues associated with petroleum project valuations and provide an appreciation of how to assess the key uncertainties involved. The course will incorporate a number of short exercises to reinforce the key techniques discussed.

WHO SHOULD ATTEND?

The course is pitched to appeal to professionals with a large range of technical and commercial backgrounds and varying levels of experience seeking insight to the broad range of economic valuation techniques required across the industry. In addition, for those employed by financial, commercial, legal, insurance, governmental, service, supply and advisory organisations, the course will also provide a valuable overview of the micro-economic issues facing oil and gas project operators .

ECONOMICS OF THE OIL SUPPLY CHAIN

INVINCIBLE energy INSTITUTE

COURSE DATES:
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On this **five-day course**, delegates will examine the various activities of the fictional Invincible Energy Company to explore the economic forces which drive the oil supply chain. They will concentrate on the main areas of risk and opportunity from the crude oil supply terminal, through transportation, refining and trading to the refined product distribution terminal.

During their time in Invincible's refinery, delegates will learn about the quality aspects of product supply. They will study refinery process economics and the effects of upgrading.

WHO SHOULD ATTEND?

This course is the essential foundation for people entering the oil industry or for those with single-function experience looking to broaden their knowledge. It also forms the basic building block for the other trading-related courses.

TRADING OIL ON INTERNATIONAL MARKETS

INVINCIBLE energy INSTITUTE

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Exercises are performed in syndicates, with comprehensive debriefs studying the consequences of the decisions made. The course expects a high degree of participation from delegates.

INTRODUCTION TO LUBRICANTS

K²M Knowledge 2 Market energy INSTITUTE

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This **two-day course** is designed to provide an overview of the lubricants business for those personnel needing a working knowledge of it, but in a limited amount of technical detail. The broad scope of the course will allow those new to the industry, or those with some experience of it, to draw immediate benefits from their increased knowledge to the advantage of themselves and their organisations. The environmental aspects of lubricants will be explored during the programme, together with their impact on the business itself.

WHO SHOULD ATTEND?

The course is pitched to appeal to Lubricant Buyers, Analysts, Planners, New Personnel to the Oil Industry, Lubricant Sales Personnel, Fleet Operators, Oil Company Sales and Marketing Personnel, Environmental Issues Personnel, Oil Company Strategy and Planning Staff, Additive Manufacturers and Suppliers.

LNG - LIQUEFIED NATURAL GAS INDUSTRY

energy INSTITUTE

COURSE DATES:
17 - 19 November, 2004

COURSE VENUE:
London, UK

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NON-MEMBER:
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This **three-day course** covers technical and commercial perspectives of all segments of the LNG gas supply chain from gas field development, liquefaction processes, shipping, re-gasification, storage, supply into a gas distribution network, embedded opportunities for LNG within existing gas markets, supply and construction contracts, project finance and economic valuation. This differs from other LNG courses in providing an integrated insight to the technologies, the markets, the economics and the finance of the industry.

WHO SHOULD ATTEND?

Those working in the LNG industry in production, liquefaction, transportation and receiving, including those reliant upon LNG supply or the financing of LNG projects; analysts, planners and commercial staff; personnel operating in the gas, electricity and related energy industries and markets, regulators, advisors and policy makers, bankers, financiers, legal advisors and risk managers.

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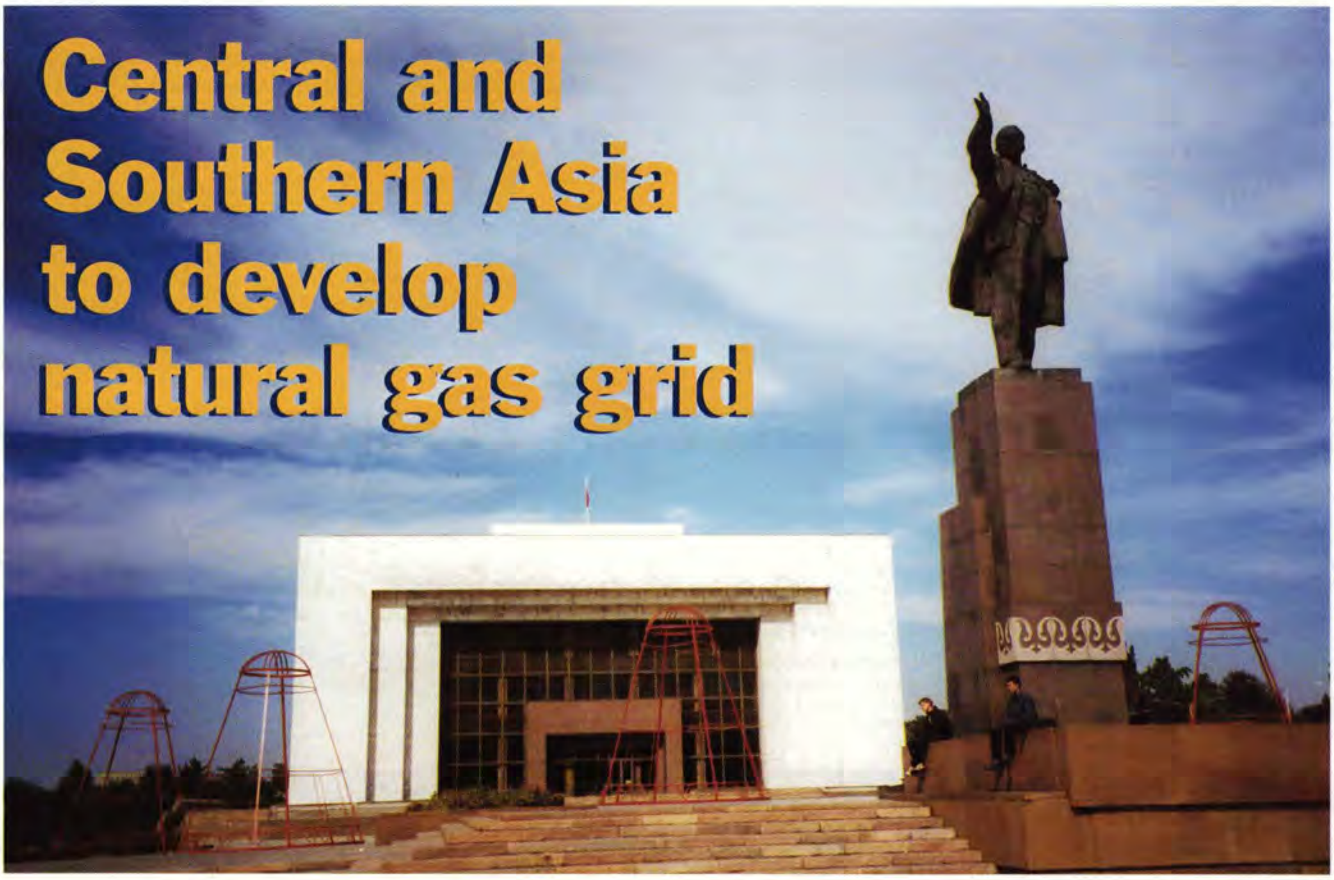
Central and Southern Asia to develop natural gas grid



Some 15 years after the collapse of the Soviet Union, plans to expand the use of natural gas in Central Asia and develop gas reserves for export are approaching an advanced stage of preparation – raising hopes that several long-touted gas pipeline projects will finally move ahead to the construction phase. *David Hayes* reports.

National museum and Lenin monument, Bishkek, Kyrgyzstan
All photos: David Hayes

Natural gas has the potential to become a major energy source in Central Asia, a region where huge reserves lie scattered among several countries but remain largely undeveloped for local use. In addition to developing gas reserves for regional use, gas-rich Central Asian republics – particularly Turkmenistan – are keen to build pipelines to export gas to promising new markets. Plans include building gas transmission pipelines to connect Central Asia with Europe and South Asia. In addition, there is the possibility of a gas pipeline being constructed from Central Asia to China and East Asia, where gas demand is expected to grow rapidly.

At present the Asian Development Bank (ADB) is due to appoint a new team of consultants to carry out a new technical and economic feasibility study on the proposed construction of the Turkmenistan-Afghanistan-Pakistan (TAP) transmission pipeline. The decision to appoint a new team follows the rejection by the tri-nation TAP gas pipeline project ministerial steering committee of the original, recently completed pipeline route and feasibility study prepared by UK company Penspen. While no formal statement has been issued, it is believed that Turkmenistan rejected the Penspen feasibility study because it was based on a gas reserve figure for Turkmenistan's Dauletabad gas field that does not take into account some recent new gas discoveries located nearby. The ADB, which funded the feasibility study, also is rumoured to be disappointed with the study.

A separate team of consultants is currently carrying out a certification exercise on the Dauletabad gas field's reserves in preparation for detailed planning to begin on the TAP gas pipeline project. Located in southeast Turkmenistan, the Dauletabad field has reserves exceeding 25tn cf – making it one of the largest gas fields in the world. The new technical and economic feasibility study on the TAP gas pipeline will be based on the newly calculated figure for the Dauletabad gas field's certified reserves.

The TAP gas pipeline project involves constructing a large-diameter, high-pressure gas pipeline up to about 1,650 km in length to transport up to 30bn cm/y of gas from the Dauletabad fields to consumers in Pakistan, Afghanistan and possibly India. The final cost of the project is estimated at between $2bn and $2.5bn. Pipeline construction will take about three years to complete once all key decisions are taken by the cooperating countries.

In addition to the gas pipeline, Turkmenistan, Afghanistan and Pakistan are believed to be considering a proposal to build a parallel crude oil pipeline running from Turkmenistan to Pakistan. The combined cost of constructing parallel oil and gas pipelines is estimated at about $4bn.

Political tensions

Short of energy, India needs new gas supplies. However, there have been concerns that that political tensions with Pakistan could affect the security of piped gas supplies in the future. Security concerns about the pipeline passing through Afghanistan are another issue.

In fact, India has already expressed interest in another gas pipeline that would transit Pakistan. The proposed scheme – for which Snamprogetti of Italy will carry out a technical feasibility study in mid-2004 – is due to run from Iran, across Pakistan, to northern India.

The governments of Turkmenistan, Afghanistan and Pakistan have jointly invited India to participate in the TAP pipeline, and Iran is keen to export its gas, but doubts surround India's participation in both projects as tense relations between India and Pakistan have worried the Indian authorities about the security of gas supplies for any scheme that transits Pakistan. 'We don't feel sure and we do not want to take a security risk,' commented a source at Gail, India's gas pipeline grid operator. 'We are not sure if gas will be regularly available. There is still a tension between the two countries.'

India's growing energy requirements could provide a market for both Iranian and Turkmen gas. According to forecasts India's energy demand growth could result in supply falling short of demand by the equivalent of 40bn cm by 2007 if additional energy supplies are not secured. With the TAP pipeline likely to carry 30bn cm of gas and the Iran-Pakistan-India pipeline a further 30bn cm, the combined capacity would be about 60bn cm – of which Pakistan is expected to buy around 15bn cm, although the exact requirement has not been calculated. This would leave almost 45bn cm of gas for India, sufficient to cover the forecast energy shortfall, as Afghanistan's gas needs are likely to be quite modest

While India's participation in the pipeline project could easily double the volume of gas that Turkmenistan could export through the TAP pipeline, the Pakistan Government believes that Pakistan's gas demand alone is sufficient to ensure the pipeline's economic viability. The country is expected to face a gas shortage of 500mn cf/d over the next five years.

However, although Pakistan's actual gas consumption could be lifted further if sufficient additional supplies were available, it is likely that Turkmenistan, Afghanistan and Pakistan will continue to work to include India in the project – a position favoured by the US Government, which wants American energy companies to invest in developing Central Asia's vast oil and gas resources.

As part of preparations for the project, Pakistan is looking at using part of the depleted Sui gas field to store gas imported from Turkmenistan. The Ukrainian Government is understood to have dispatched a team to Pakistan to help plan the creation of underground storage facilities that can hold 60 days' supply of Turkmen gas.

TAP consortium

The TAP pipeline tri-government steering committee has already agreed that a consortium will be established for the construction and operation of the gas pipeline. Led by one or more major international oil and gas companies or gas transmission companies, the TAP pipeline consortium will comprise a holding company and local subsidiary companies in Turkmenistan, Afghanistan and Pakistan. In addition to having the right to design, construct and operate the pipeline, the consortium will have the exclusive right to transport the Turkmen gas to markets in Afghanistan and Pakistan. The consortium will also have the right to design, finance, construct, hold majority ownership, operate, maintain and expand the pipeline capacity in all the three countries.

Two routes for the TAP pipeline have been proposed across Afghanistan to Pakistan – one crossing northern Afghanistan and the other crossing southern Afghanistan. Although Pakistan and, potentially, India would be the major markets for the Turkmen gas, Afghanistan's position as a transit country would allow the local gas utility, Afghan Gas, to gain access to gas supplies as well.

The southern route – favoured by Afghanistan and Pakistan – would pass through Herat and Kandahar in Afghanistan before crossing the border to Quetta in Pakistan and continuing on to Multan, where it would join Pakistan's existing gas grid. The northern route – which the ADB is understood to favour – would pass through Sheberghan and then Kabul, before continuing to Islamabad and Lahore in Pakistan.

At a meeting in June 2003 in the Turkmen capital, Ashgabat, Afghan and Pakistani representatives rejected the northern route because it would take the pipeline over Afghanistan's mountains and the difficult Salang Pass. They also argued that there was proper infrastructure already in place at Multan for building the pipeline.

This is not the first time that the construction of a Turkmenistan-Afghanistan-Pakistan gas pipeline has been proposed. In 1997, six international energy companies led by America's Unocal and the Government of Turkmenistan formed Central Asia Gas Pipeline (CentGas) to build a 48-inch diameter, 1,440-km gas-pipeline crossing Afghanistan to link Turkmenistan with Pakistan. However, with the Taliban in power the political situation in Afghanistan deteriorated. Unocal withdrew from the project in 1998 and it was abandoned the following year.

Wider cooperation

Meanwhile, plans to expand the use of natural gas in Central Asia are currently under preparation as part of a wider regional initiative to increase cooperation in the development and exchange of energy among five neighbouring countries – Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan. Consultants funded by an ADB technical assistance grant are preparing proposals for a project suitable for ADB funding to support development of the Central Asian gas pipeline transmission grid and the growth of cross-border gas trade among neighbouring states.

Gas transmission grids in each of the five countries will be renovated and expanded. Among new facilities planned, a new parallel gas pipeline is expected to be built from Uzbekistan, through Kazakstan, into Kyrgyzstan and then back into Kazakhstan.

Recommendations on establishing the necessary legal and commercial framework to allow the operation of an efficient regional gas trading system are also under preparation. These will support wider efforts to encourage cross-border cooperation in developing the region's vast energy resources, including hydroelectric power.

While western oil and gas companies are interested in helping Central Asian countries develop their gas reserves, Russia also recognises the strategic importance of the region's gas resources to its own gas industry. Gazprom, for example, has recently increased its involvement in Central Asia's gas market, seeking low-cost gas supplies to replace its own declining reserves. In addition to signing gas purchase contracts with Turkmenistan and Uzbekistan, Gazprom has recently also signed gas supply contracts with Kyrgyzstan and Tajikistan to help the two countries solve some of their energy shortage problems.

Street scene, Tashkent, Uzbekistan

Although the creation of a Central Asian gas grid would be of benefit to all the regional states, Turkmenistan, Uzbekistan and Kazakstan are also interested in supplying other foreign markets, for which they will have to compete against each other and Russia, which wants to increase gas supplies to Europe and plans to supply China, South Korea and Japan. Russia is well aware of the competitive threat its gas industry faces and is trying to encourage gas-producing Central Asian republics to use its pipeline routes to reach western markets.

Changes will be needed in Central Asian countries' relations with each other to increase the regional gas trade. Following the break-up of the Soviet Union and their resulting independence, most Central Asian countries have avoided becoming dependent on outside sources for energy, generally preferring national policies that favour self-sufficiency and import substitution. As a result, regional energy trade, including gas sales, currently operates through a complex structure of state-to-state barter arrangements that are neither efficient nor able to effectively meet the changing needs of the individual countries.

To ensure the effective functioning of a regional gas grid, the existing policy framework of the five Central Asian republics will need to be adjusted to allow the introduction of a market-orientated energy structure. As part of efforts to introduce such a structure, gas tariffs will need to be adjusted to permit real cost recovery while problems with non-payment for energy services need to be resolved.

Regional resources

Due to the region's large reserves, natural gas already is a major energy source in Central Asia, where an extensive gas pipeline transmission network dating back to the former Soviet Union is in existence. The gas transmission systems were established in the Soviet era when gas was transported from the former Central Asian Soviet Republics to the northwest as feedstock for the major refineries in European Russia.

With the discovery of natural gas in Siberia, exports to these traditional markets declined. However, gas continued to be supplied through the pipelines to other republics in the former Soviet Union.

Since the end of the Soviet era the new Central Asian republics have taken over ownership of the gas pipeline networks in their territories. However, inadequate gas transmission infrastructure and a lack of investment resources to expand and develop the gas pipeline networks have prevented the region's huge gas reserves from being exploited fully and from playing a more important role in promoting regional economic growth.

Official figures show Turkmenistan having the largest estimated proven natural gas reserves in Central Asia, totalling about 98tn cf, followed by Uzbekistan with around 66tn cf and Kazakhstan with about 65tn cm. Both Kyrgyzstan and Tajikistan have far smaller reserves of about 200bn cf each and consequently rely on imports to supplement their limited gas production.

Turkmenistan and Uzbekistan are Central Asia's two largest gas producers, followed by Kazakhstan. Turkmenistan currently produces about 2.5tn cf/y, while Uzbekistan's output is around 2tn cf/d. Kazakhstan produces about 200bn cf/d, while Tajikistan produces 700mn cf and Kyrgyzstan 350mn cf.

Uzbekistan, because of its geographical location, is at the centre of the existing regional gas grid. However, most of the country's gas production is consumed domestically for power generation and to manufacture petrochemicals. This has reduced the amount of gas available for export to Kazakstan, Kyrgyzstan and Tajikistan. Exports also are limited by the region's inadequate gas grid pipeline network and the lack of alternative routes to the existing transmission network connecting Central Asia to central Russia. The western section of this pipeline network connects Turkmenistan with Uzbekistan and the Russian Federation, while the eastern section was built between 1967 to 1969 and connects Uzbekistan with Kyrgyzstan, Tajikistan and Kazakhstan.

The eastern pipeline section originates at Bukhara in Uzbekistan and passes through the capital Tashkent, continuing on to Bishkek in Kyrgyzstan, before terminating in Almaty, the former capital of Kazakhstan.

Non-payment problems

Another important factor holding up gas trade development is frequent non-payment for exported natural gas by the recipient countries, which has discouraged gas exporters from supplying them. In particular, Uzbekistan has faced continuing problems collecting gas payments from cash strapped Kyrgyzstan and Tajikistan, which has resulted in frequent disruption to the two countries' gas supplies.

Plans to increase gas supplies from Uzbekistan to Kyrgyzstan, Kazakhstan and Tajikistan as part of the proposed ADB-funded regional gas trade development project will first require an assessment of available gas reserves in Uzbekistan and Turkmenistan that could be developed for use in Kazakhstan and Kyrgyzstan.

Gas transmission systems in the various countries have deteriorated considerably due to a lack of maintenance and other factors. These gas transmission networks will need to be rehabilitated and upgraded to ensure the continuation of reliable gas supplies.

Uzbekistan has recently begun expanding gas production following the signing of a long-term gas supply contract by state-run gas company Uzbekneftegaz with Gazprom of Russia in late 2002. Under the agreement Gazprom will purchase up to 10bn cm/y from Uzbekistan from 2003–2012 to partly replace the growing shortfall of gas production from Gazprom's own depleted gas fields in Russia.

While the national gas companies in Central Asia are interested in supplying new customers, another constraint is the fact that the existing transmission pipelines follow routes that represent the economic interest of the former Soviet Union rather than being designed for the interest of the individual Soviet republics. This situation has held back development of the gas industry in Kazakhstan, for example, which is connected by six pipelines to other countries in Central Asia and the Russian Federation.

In spite of its large gas reserves, Kazakhstan's western gas producing areas are not connected to the country's main gas consuming areas in the industrial north and populous southeast region. Instead of consuming its own gas, Kazakhstan mainly exports gas produced in the western region to the Russian Federation and has to import about 40% of its domestic natural gas requirement for the southern part of the country from Turkmenistan and Uzbekistan.

Turkmen plans

The future economic prospects of Turkmenistan, meanwhile, are dependent largely on its ability to increase its natural gas exports. However, due to the country's location and neighbouring Uzbekistan's large natural gas resources that traditionally have supplied most of Kyrgyzstan and Tajikistan's needs in addition to the domestic Uzbek market, Turkmenistan is not a major natural gas supplier to other countries in the Central Asian region.

Turkmenistan currently has to export gas through Russia. After Turkmen gas has entered the Russian Federation through the western section of the Central Asia-central Russia transmission network, Turkmenistan has to use the old Russian transmission pipeline network to export gas to third-party countries. This has seriously limited its gas export capability.

Gas analysts believe that Turkmenistan could easily double its existing gas production if the pipeline transmission network was expanded and upgraded to supply new markets. The only new gas pipeline built recently is a transmission network about 200 km in length that supplies gas to northern Iran.

Apart from plans to build the TAP pipeline to supply Pakistan and possibly India, Turkmenistan also wants to build gas transmission pipeline networks to export gas to China, Southeast Asia and Europe. The country's ambitions to supply Europe were one of the reasons prompting Gazprom of Russia to sign a 25-year gas supply agreement with Turkmenistan in April 2003, pre-empting the possibility that Turkmenistan would try to supply Botas of Turkey via a pipeline through Iran that would compete directly with Gazprom's own Blue Stream pipeline that supplies gas to Turkey under the Black Sea.

Russian interests

Gazprom has contracted to purchase 5bn cm of gas from Turkmenistan in 2004, rising to 7bn cm in 2005, 10bn cm in 2006 and 60–70bn cm in 2007. Longer term, Gazprom has agreed to buy 70–80bn cm from 2010–2028. The gas price for 2004 and 2005 is set at $44/1,000 cm and will be linked to international oil prices afterwards. Turkmen gas will be used to relieve gas shortages facing Gazprom due to declining production in all the company's major gas fields.

In addition to purchasing gas, Gazprom has agreed to participate in the construction of a 3-bn cm/y capacity gas transmission pipeline at an estimated cost of $1.2bn, to connect Turkmen gas fields with Gazprom's domestic pipeline network, bypassing Uzbekistan. The pipeline is due for completion in 2007 and will follow a route along the Caspian Sea.

Gazprom also has agreed to submit a detailed proposal to Turkmenistan for the rehabilitation and modernisation of the existing Central Asia Central (CAC) pipeline, which is the only transmission route that Turkmenistan can use to export any sizeable volume of gas at present. Built to carry 90bn cm/y, the CAC pipeline can only transport 45bn cm/y at present because of inadequate maintenance and its current poor state of repair. Gazprom has agreed to provide technical and other support to upgrade the CAC pipeline section in Turkmenistan. Gazprom is also liaising with Uzbekistan and Kazakhstan to upgrade CAC trunklines that pass through both countries.

Meanwhile, Gazprom is fulfilling the second year of a two-year commitment to provide Tajikistan and Kyrgyzstan with reliable gas supplies, which is reducing the two countries' previous dependence on Uzbekistan for gas while giving Gazprom a further foothold to develop gas and other energy business opportunities in Central Asia.

In May 2003 Gazprom signed agreements with Tajikistan and Kyrgyzstan to ensure both receive regular gas supplies in 2003 and 2004 and to help both countries develop their own limited natural gas resources. Cooperation will be provided to repair and upgrade gas and oil wells. Gas pipelines will be repaired as well. However, both countries will remain dependent on gas imports in the future owing to the small size of their own reserves.

Gazprom is supplying gas to Tajikistan and Kyrgyzstan taken from Gazprom's own purchases from Turkmenistan and Uzbekistan. However, Tajikistan and Kyrgyzstan have to pay Gazprom for the gas and not the producing countries.

Meanwhile, Gazprom's recent closure of contracts to purchase gas from Turkmenistan and Uzbekistan also will provide the company with important supplies to cover shortfall in production from its own declining fields. The availability of Central Asian gas means that Gazprom can defer development of gas reserves in Russia's Yamal peninsular that will be difficult and costly to exploit. Deferring investment in developing the far flung Yamal reserves means that more funds are available for Gazprom to carry out a much needed pipeline and gas production infrastructure maintenance and upgrading programme.

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Please send an email to: **mailing@energyinst.org.uk** stating what problems you are experiencing together with your membership number and postal address.

Many thanks

EN13094 – an operator's dream or a manufacturer's nightmare?

A new manufacturing standard – EN13094 – focusing on the safety of road tankers transporting dangerous goods, including petroleum, will be applicable in the UK from 1 July 2005. Although the implementation of this legislation promises to bring better standards of manufacture and more controlled testing of safety measures to the operator, there is a downside – it will also cost money. *Chris Dalton*, Managing Director of Heil Trailer International in the UK, explains why.

The new design code EN13094:2004 specifies minimum requirements for the design and construction of metallic tanks used for the transportation of dangerous goods, with a maximum working pressure not exceeding 50 kPa – such as petroleum spirit tankers. The code which was drawn up by CEN (the European Committee for Standardisation), the code was approved on 21 February 2004. It has been supplied by the BSI Technical Committee and recognised by the UK Department for Transport as the interim design code satisfying the requirements of Directive 2003/28/EC.

What are the implications?

EN13094 brings a standard build code to the industry, referenced under ADR regulations. However, it should be remembered that EN13094 only provides the basis of the code – even if adopted as the standard throughout Europe, national governments can add local adaptations, thus creating a less than level playing field.

The new code will result in a number of changes to the design and manufacture of tanks. For example, it requires the implementation of a calculation method. Here, at Heil Trailer International, we have over the past two years developed a calculation method as required under annex 5 of the code, to verify the strength of all aspects of the tank, such as the barrel, heads, partitions, openings and lids under both service and test conditions, including the dynamic forces the tanks experience under transport conditions. All Heil engineers will be trained in the use of this calculation, to ensure that all new designs are fully compliant with the standard.

Changes are also required to areas such as the design of trailer top protection, in order to comply with new strength standards set out in the code. For example, between the coamings there must be a transverse beam at intervals of 3 metres, in order to strengthen the coaming. There must also be a minimum of 25 mm from the top of the service equipment to the top of the coaming or protection. Heil has upgraded the design of its trailers by developing new extrusion beams to provide full protection all along the tank top.

Other areas where manufacturers will be affected include:

- Ensuring all materials and thickness standards are fully compliant, such as a minimum compartment dish depth of 250 mm.
- Manhole sizes, with a required minimum diameter of 500 mm.
- Manufacturing tolerances, covered in section 7.5, which clearly states the tolerance allowed for welding different plate thicknesses, and plate alignment. The code defines the maximum bulge or dent in a material plate to be not greater than 2% of their length or width.
- Working the materials – the code introduces practices such that the degree of shaping required by a particular shell design does not generate cracking or other signs of distress in the shell material. Areas such as cutting, edge preparation, forming and welding are all covered.
- Ensuring all welding is to the standard maintained in EN13094, and taking special consideration when welding temporary attachments.

There are references to at least ten other EN codes dealing specifically with welding.

- Compliance with UNECE Reg 111 related to rollover stability, which states a sideward G force of 4 m/s^2 or 23°.
- The implementation of EN12972 relating to testing, inspection and markings of ADR tanks. This EN standard goes hand in hand with EN13094, and between them they cover the design, construction and testing of tanks both as a newbuild and during the service life of the tank. The key element in this standard is that from July 2006 tank testing must be undertaken by a third party.
- All service repairs must be checked and approved by a third party.

The new code also requires design verification by a third party. A dossier giving evidence of the design verification must be prepared and submitted to the Competent Authority for approval. In the UK, the Competent Authority is the Department for Transport (DfT) – Dangerous Goods Branch. The DfT can delegate this authority to third-party insurers such as SGS and Lloyds.

The design verification dossier must contain information on the calculations used for the barrel, partitions, heads and openings of the tank. It can make reference to existing designs, but there must be at least five examples. It is expected that the requirement for the design verification alone will add £300–£400 per design submission to the cost of the tank manufacture.

New Publications

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Marine Technology Directorate (MTD) titles now available from the Energy Institute

The Energy Institute (EI) has assumed ownership of the publications relating to the offshore and marine sector previously published by the Marine Technology Directorate (MTD). These publications include a number of internationally important titles such as *Guidelines for the avoidance of vibration induced fatigue in process pipework* (available as a CD-Rom), *Floating Structures: a guide for design and analysis* and *Guide to quantitative risk assessment for offshore installations.*

The EI is pleased to be able to support the industry by continuing to make these important publications available following the decision to disband MTD as an independent organisation.

MTD, set up in 1976 by the Science Research Council, was responsible for facilitating cooperative projects between industry, academia and government in research, and education and training in marine technology: covering all aspects of science, engineering and technology relating to the exploration and exploitation of the sea, both above and below the seabed. MTD managed research projects in support of offshore oil and gas production, subsea technology, ships and transportation, ocean environment and non-hydrocarbon resources. It was a recognised publisher of guidelines and other material resulting from its research programme, which, at its peak, represented an annual research spend of £8.6mn.

A full list of MTD publications is available on request from the EI and will shortly be published online. Visit **www.energyinst.org.uk** and follow the links from the 'Publications' page.

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Hopes for progress

Exploration in the Gulf of Guinea's latest hotspot – the São Tomé-Nigeria Joint Development Zone (JDZ) – is set move ahead, writes *Maria Kielmas*.

Just as the Presidents Fradique de Menezes of São Tomé & Principe and Olusegun Obasanjo of Nigeria were meeting in Abuja to discuss future licence awards in the nine-block offshore São Tomé-Nigeria Joint Development Zone (JDZ), São Tomé was plunged into darkness. This is a regular occurrence when state fuel distributor Empresa Nacional de Combustiveis e Oleos (ENCO) runs out of money to pay for oil deliveries from Angolan state-owned Sonangol and thus cannot supply the local power utility Empresa de Agua e Electricidade (EMAE).

Local commentators have noted the irony that a sparsely-populated (approximately 180,000 inhabitants) archipelago located in the middle of one of the world's most prolific hydrocarbon provinces can run out of oil.

Industry speculation

Ever since São Tomé and Nigeria settled their maritime border dispute through the creation in 2001 of the São Tomé-Nigeria Joint Development Zone (JDZ) – which is administered by a bilateral Joint Development Authority (JDA) – this area has become the focus of feverish industry speculation about the size of its potential oil reserves. Oil reserves of between 5bn and 15bn barrels have been suggested. Indeed, São Tomé and Principe (STP), which was only famous for its cocoa exports, has been touted as a second Kuwait and as a future host to the largest US military base outside the Middle East.

However, oil exploration here has been dogged by controversy and uncertainty since 1995 when the government signed a contract with Houston-based Environmental Remediation Holding Corporation (ERHC) to explore and promote its entire offshore region. In return the company paid salaries of up to $4,000 per month to some STP government officials and provided their children with an education in the US. The deal triggered outrage among multilateral agencies and, with the assistance of the World Bank, was modified twice in the international arbitration courts.

As a result, ERHC holds between 15% and 30% of preferential rights in JDZ blocks 2, 3, 4, 5, 6 and 9. If it opts to exercise these rights, it only needs to pay signature bonuses in blocks 5 and 9. So, when the JDZ licensing round was opened in April 2003, aspiring bidders were uncertain of what to expect from ERHC. The JDA had informed foreign oil companies that they would have to negotiate an agreement with ERHC outside of the licensing round. The company was now 80% controlled by Nigeria's Chrome Oil, whose owner, Emeke Offor, was previously linked with the family of former President Sami Abacha. However, Offor is now believed to be within the patronage of Vice President Atiku Abubakar. He has also twice helped STP President Menezes with election campaign finance.

When bidding closed in October last year, some 20 companies had submitted 33 bids for eight of the nine offshore blocks (see **Table 1**). A total of $500mn was pledged in signature bonuses – far short of the $5bn or so that the JDA had been expecting. Not only did fewer international majors participate in the round, but the majority of the bidders were Nigerian-owned companies with strong links to major political and military figures in Nigeria. Furthermore, they had neither the financial capability of paying the signature bonuses nor the technical capability for expensive exploration in the Gulf of Guinea deep waters. Bidders Conoil and ECL International, controlled by Mike Adenuga, have been linked with General Ibrahim Babangida, while Atlas Petroleum has been linked with the family of Sami Abacha. Under the JDZ petroleum legislation, the signature bonuses are neither tax deductible nor cost recoverable.

Company	Blk 1	Blk 2	Blk 3	Blk 4	Blk 5	Blk 6	Blk 7	Blk 8	Blk 9
Anadarko (US)		30		40					
Atlas Petroleum (Nigeria)	55			40					
Centurion Energy (Canada)	60	45		50					
ChevronTexaco (US)	123								
Conoil (Nigeria)	120								
ECL International (Nigeria)				100					
Energy Equity Resources	61			33					
ERHC/Chrome (Nigeria)	60	60							
FiltimHuzod (Nigeria)						32			
Foby Engineering (Nigeria)		113				35			45
Fusion Oil (Australia)					10		10		
Maurel & Promo (France)						55			
NPDC (Nigeria)	50	30							
Ocean Energy (US)	57.5								
Oil & Gas (Nigeria)	40.2			41.5					
Petrocamak Europe (UK)				70					
Sahara Energy (Nigeria)			35		35	35			
SEO International (US)	106.3								
Statoil (Norway)	60								
Suntrust Oil (Nigeria)	45								

Source: JDA, G Seibert

Table 1: JDZ bidding results, October 2003. Signature bonuses in $mn

Licensing award

The STP announced the final award of block 1 to a ChevronTexaco-led consortium in April this year. ChevronTexaco has a 51% interest in the block, with ExxonMobil holding 40% and Energy Equity Reservoirs (EER) the remaining 9%. The group structure was put together by the JDA following a meeting between Presidents Menezes and Obasanjo. EER is controlled by the Dangote group, Nigeria's largest corporation and whose owner, Aliko Dangote, is President Obasanjo's godson. Dangote has also been tipped to run for the Nigerian presidency in 2007. The minority partner in EER is Norway's Terra Resources, an offshoot of seismic company PGS.

The JDA also confirmed the pre-emptive rights held by ERHC/Chrome, leading to a continued rise in the company's share price on the US stock markets on the belief that it could make hundreds of millions of dollars from its JDZ interests. According to industry sources ExxonMobil turned down requests from President Menezes to take up stakes in two other blocks in which it had pre-emptive rights because this would involve doing business with ERHC/Chrome.

After April the licensing process seemed to stall. Industry executives were reluctant to commit either the large signature bonuses expected or to negotiate with ERHC/Chrome. In addition, there had been no progress on the successor to the JDA Director General, Tajudeen Umar. A Nigerian former diplomat and civil servant, Umar was supposed to have been replaced at the end of 2003. The agreement between STP and Nigeria allows for a two-year alternating chairmanship.

However, by mid-June things were looking better. Umar had been replaced by Carlos Alberto Bragança Gomes, the JDA's São Tomean Deputy Director. Gomes is a former Agriculture Minister and also the government official who first decided to cancel ERHC's contract in the late 1990s. But, like all other São Tomé oil officials in the mid-1990s, he had previously been on ERHC's payroll. For its part, ERHC/Chrome announced a Memorandum of Understanding with Pioneer Natural Resources to jointly evaluate and negotiate block 2 in the JDZ.

JDZ transparency initiative

By late June Presidents Menezes and Obasanjo had signed a joint declaration regarding the transparency and governance of the JDZ. Under the agreement the JDA will publish an annual budget approved by both governments. Its accounts and procurement contracts will be audited by an internationally recognised firm and the audits will be made public. All of the financial information regarding production sharing and third-party procurement contracts will also be made public. In addition, the JDA will publicise the basis for all awards in the JDZ, including the technical and diligence analysis. Bids and supporting data, other than proprietary data, will also be made public.

The two governments hope that this transparency initiative will prompt a more enthusiastic response from the international oil industry. STP officials have hinted that another bidding round could be held within a year, once PGS completes an additional seismic survey over blocks 2 and 4. Earlier this year the JDA tried, and failed, to persuade companies who had filed bids to re-apply for their blocks. The big question is whether European oil companies such as Shell and Total, who were notably absent from last year's licensing round, may show some interest in future rounds.

Final decisions

However, the whole exercise depends on the decisions of President Obasanjo. According to Lisbon-based regional specialist Gerhard Seibert, Obasanjo takes the final decision on the make-up of the JDA and the awards of acreage. Even though he cannot stand in the 2007 elections, he is unlikely to award acreage to companies linked to his political opponents.

Meanwhile, in São Tomé a private US security company, Military Professional Resources Inc (MPRI), is conducting a year-long defence assessment of the islands for the STP Government. The Pentagon has denied any knowledge of MPRI's dealings in the STP. The company previously tried to provide a similar defence assessment for Equatorial Guinea – but this was halted by the US Government.

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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. 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, as well as those at the forefront of technology 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 to those 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 – Energy Advisory Services
- Professor Sue Roaf – Oxford Brookes University
- Sam Heath – London Renewables
- 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

Companies already attending comprise:

ConocoPhillips
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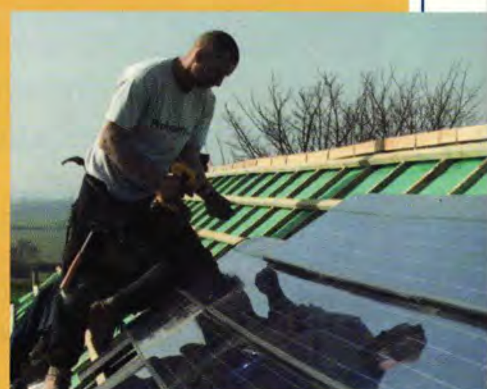

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EI Autumn Lunch

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Guest of Honour and Speaker

Jeroen van der Veer (right)

Chairman of the Committee of Managing Directors (CMD) of the Royal Dutch/Shell Group of Companies and President of Royal Dutch Petroleum Company

Wednesday 20 October 2004
Claridges Hotel, Brook Street, London, W1

The Autumn Lunch is a traditional and well-respected event that has long been an established date in the oil and gas industry calendar.

This year we return to the elegant surroundings of Claridges Hotel, London, to once again enjoy their unrivalled hospitality.

A 3-course lunch of the highest standard will be followed by an extremely informative speech from one of the industries most sought after Senior Executives.

Tickets: £142.00 + VAT

Jeroen van der Veer's career has included manufacturing operations in Curaçao and Pernis in the Netherlands as well as postings in Corporate Planning for Shell Nederland, and in marketing with Shell UK's liquefied petroleum gas business, extending and restructuring it to achieve profitability.

Jeroen was appointed Chairman of the Committee of Managing Directors (CMD) in March 2004. He joined the CMD from the Shell Chemical Company in the USA, where he was President and Chief Executive. In the USA he was involved in the transformation of Shell Chemical (a part of Shell Oil Company) and he sponsored the reward and recognition initiative. This reflects his strongly held view: it is important to allow people to contribute to Shell in their own way while the leadership helps them to focus their energy on what matters. Jeroen has been appointed an Advisory Director of Unilever and serves as a member of the Nomination and Remuneration Committees.

To apply for tickets, please complete this form in BLOCK CAPITALS and return it to the address below, together with payment in full.
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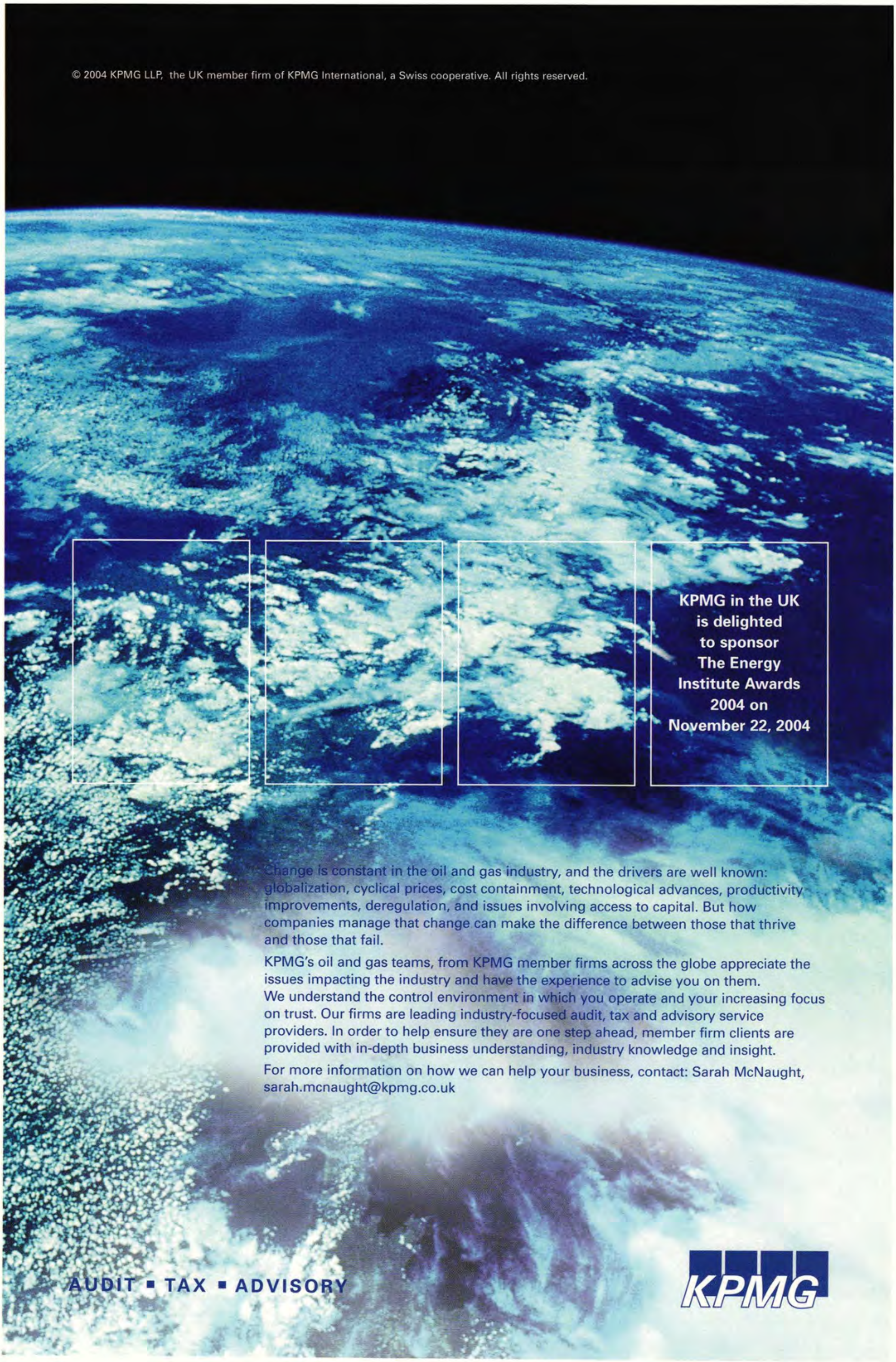
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