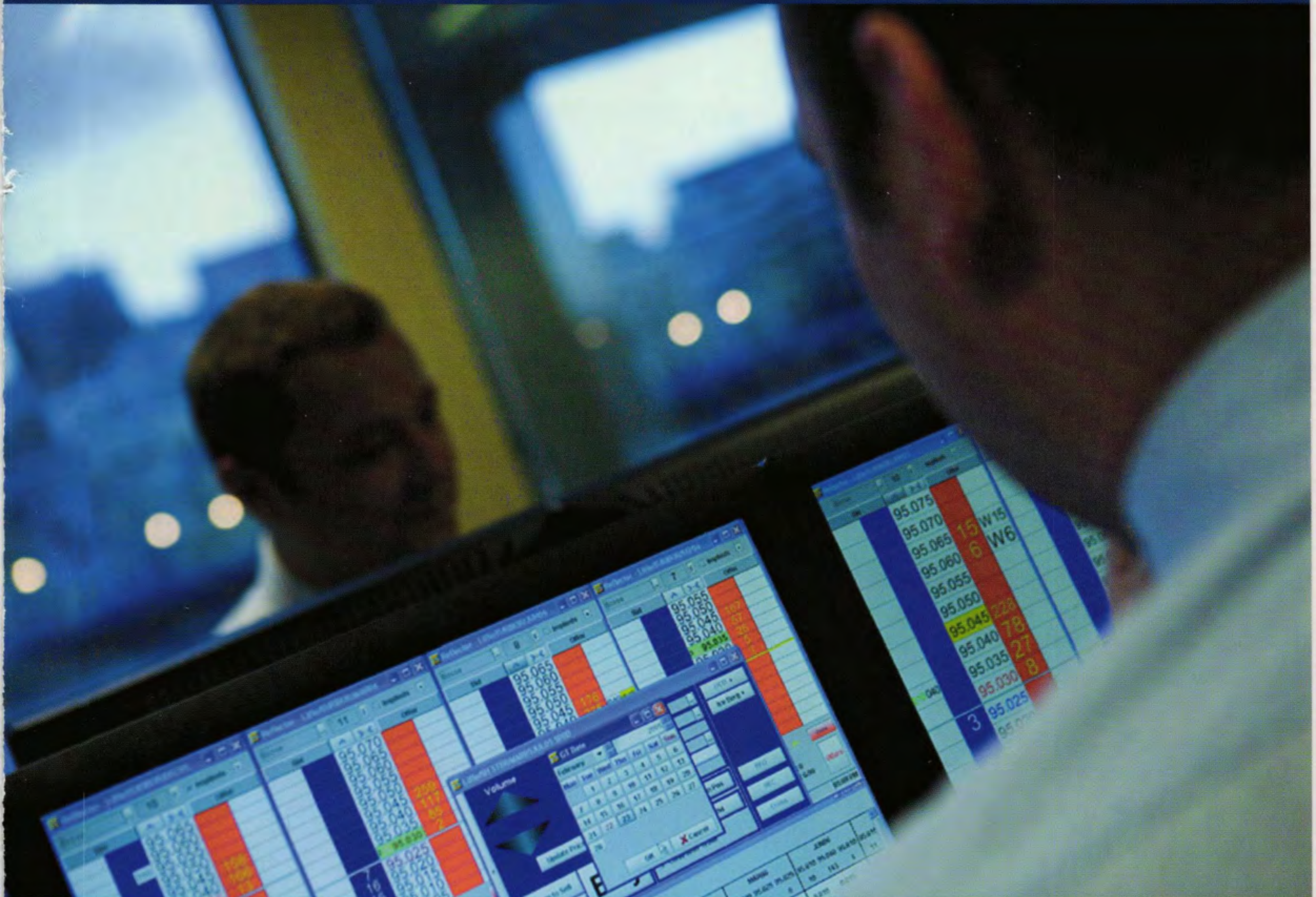
JUNE 2005

Petroleum review



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The Cadman Lecture

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Continuing the Oil and Gas Adventure

Thursday 23 June 2005

Old Hall and Crypt, The Honourable Society of Lincoln's Inn,
Holborn, London, WC2A 3TL

Presented to: *Michel Contie, Managing Director, Total E&P UK*

Michel Contie, Managing Director of Total E&P UK, is the recipient of this year's Cadman Award, presented by the Energy Institute. This is one of the EI's most prestigious awards, commemorating the late Lord Cadman of Silverdale, Chairman of the Anglo-Iranian Oil Company (now BP) and past-President of the Energy Institute (formerly known as the Institute of Petroleum).

Contie receives the award for his outstanding services to the petroleum industry and will receive the Cadman Award and present a lecture at an evening event on Thursday 23 June in London.

Beginning his career as an R&D engineer, first in France and later in the US, Contie was involved in development of new technologies for deep offshore oil developments. Within Total he has held operational and managerial positions both in Paris and various locations around the world. In 1999 he became Senior Vice-President of E&P in Latin America, covering operations and new developments in the region. In 2000 he took up the post of Managing Director of TotalFinaElf Exploration UK during the merger of TotalFina and Elf, the company having latterly been renamed Total E&P UK.

From December 2001 to December 2002, Contie was President of the UK Offshore Operators' Association (UKOOA). He is an Officer of the Ordre National de Mérite, awarded by the French government and in July 2004 was awarded a Doctorate in Business Administration by the Robert Gordon University in Aberdeen.

The Cadman Memorial Fund commemorates the late Lord Cadman of Silverdale (right), Chairman of the Anglo-Iranian Oil Company (now BP) and past-President of the former Institute of Petroleum (now the Energy Institute) and is made on an international basis for outstanding service to the petroleum industry.

The lecture will take place on Thursday 23 June at the Old Hall and Crypt, The Honourable Society of Lincoln's Inn, Holborn, London, WC2A 3TL from 17.45.

Admission, which is complimentary, is strictly by ticket only, and these are available from Jacqueline Warner, Energy Institute, 61 New Cavendish Street, London W1G 7AR, t: +44 (0)20 7467 7116 f: +44 (0)20 7580 2230 e: jwarner@energyinst.org.uk **Tickets will be available on a first-come first-served basis.**

Petroleum review

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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

Front cover picture: Trading has moved from pits to PCs. Today, anyone can view the widest variety of markets and products on a computer screen.
Photo: Patsystems

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Time to consider nuclear

This month the Energy Institute (EI) will confirm that Sir John Collins has been appointed EI President for the customary 2-year term. The EI is very fortunate in having such a successful and high-profile figure at its helm. An interview with Sir John appears on p27, along with a brief guide to his career.

The rumours are now getting louder that the UK government is looking increasingly favourably on building a new generation of nuclear power stations to replace the current ageing (and soon to be retired) fleet of reactors. The primary driver appears to be the realisation that carbon dioxide (CO_2) and greenhouse gas emissions commitments cannot be met without nuclear power because renewables generation cannot be expanded fast enough. Meanwhile, further dependence on gas-fired generation is becoming less attractive on three counts – CO_2 and greenhouse gas emissions, the likely high level of dependence on imported gas supplies and, more recently, the idea that, if gas prices remain high, gas-fired generation may cease to be the no-brainer cheapest generating option it has been over recent years.

In the US, continuing high gas prices and restricted availabilities have already led to much new gas-fired generating capacity remaining unused. The just announced take-over of Cinergy by Duke Energy has, as one of its motivations, Cinergy's large coal-fired capacity compared with Duke's high gas-fired dependence.

The international oil industry has had virtually no involvement in the nuclear industry since the ill-fated joint venture between Shell and Gulf in the late 1960s. This proved so financially disastrous that Enrico Mattei's 'Seven Sobbing Sisters' became six, with the effective demise of Gulf, which never financially recovered from its nuclear involvement, although Shell did.

As a result of this experience, oil companies have largely eschewed nuclear involvement. However, the oil industry has a number of key skills that provide a good fit with the nuclear industry. The oil companies are good at mobilising very large capital sums, they are good at delivering very large multi-year projects, they have a very good safety record and they have experience of understanding and applying new technology and financial innovation. Their public relations are also good and, most important of all, they are profits focused.

The nuclear industry desperately needs these skills. Its public relations appear weak and it has failed to promote innovative schemes to deal with nuclear waste. Its building programmes were legendary for the size and cost of their overruns and it totally failed to counter the arguments of the green and anti-nuclear lobbies, leaving effective promotion to a limited number of academics and concerned individuals. In short, they still have to get away from their secretive, high spending, military origins.

So, what specifically could the oil industry, or oil industry personnel, offer the nuclear industry? The oil industry has enormous knowledge and expertise of geology and drilling deep holes in the earth's crust. The simplest and easiest way to dispose of nuclear waste is to put it in deep wells, in small slugs separated by concrete, well below any acquifer with communication to the surface or near surface. If the geology was favourable, nuclear waste could be disposed of from within the power station perimeter fence, thereby minimising security concerns.

The feature of nuclear power is that it is best for baseload capacity and revival of nuclear power would probably require another reworking of the electricity trading arrangements in the UK. The economics of nuclear power are, in fact, remarkably like the economics of LNG production and sale. So, once again, the oil and gas industry has knowledge and expertise that can be applied.

The final, and crucial, question is would the oil industry want to become involved in the nuclear industry? This remains to be seen, but having merged to better cope with large projects, the industry now finds such projects either increasingly inaccessible (Middle East, Russia) or scarce (the rest of the world). The first quarter of 2005 produced much praised and well documented record profits for virtually all the oil majors. Less well documented was the fact that only one out of the seven largest companies managed to expand production of oil (liquids) in 1Q2005. The figures were ExxonMobil –3%, ChevronTexaco (now Chevron) –6%, Shell –8%, BP +2%, ConocoPhillips 0%, Repsol/YPF –7%. It is to be hoped that 1Q2005 was truly exceptional.

Chris Skrebowski

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

E-DATA

BP has agreed a global deal with e-learning provider SkillSoft that will allow the oil company to supply up to 80,000 users with its own custom-developed training and third-party vendor modules as well as with SkillSoft and Books24x7 content. Training and 24x7 online mentoring will be delivered through a BP customised and branded version of SkillSoft's learning management system, SkillPort. BP will also have the ability to customise SkillSoft courses if required. SkillSoft's entire courseware library of over 4,500 courses will be available to BP employees, contractors and, in some areas, customers; including courses available in 15 languages.

Small to medium-sized enterprises (SMEs) now have free access to the National Measurement System's (NMS) world measurement experts, under a new scheme launched by the UK DTI. The NMS consists of the following laboratories – NEL, NPL, LGC and NWML. The aim of the scheme is to encourage new product innovation and help SMEs to improve their business through the use of good measurement practice. Under the initiative, SMEs who contact the NMS for help and advice on measurement issues may qualify for free consultancy. The scheme is open to UK SMEs who may be experiencing measurement-related problems or who may have issues with measurements at some stage of their product development cycle. For further information on the programme, visit **www.npl.co.uk/measurement_for_innovators/**

Invensys has announced a new name for the company's e-commerce website at **www.BuyAutomation.com** – which is said to more accurately reflect the broad range of automation products and services available on the site from Foxboro, Triconex, Eurotherm, Action Instruments and other leading brands. The site was formerly known as **www.iastore.com**

Lodestar Corporation, a leading provider of software solutions for the energy industry, has released ContractExpert as a standalone, flexible, web-based product specifically built for the energy sector to manage creating, editing, approving, executing and amending contracts with all counterparties, including end-use customers. For more information, visit **www.lodestarcorp.com**

The Energy Hedge Fund Center at **www.energyhedgefunds.com** is a free online community for discussion, news, articles and polls on the activities of hedge funds in the energy industry.

UK

Malcolm Wicks has been appointed *UK Energy Minister.*

The three oil executives behind the *billion-barrel Buzzard field – the largest North Sea discovery in more than a decade – are reported to have left Canadian firm Nexen to set up on their own. Alan Booth, who was Chief Executive of Encana UK prior to Nexen's \$2.1bn takeover last December, has formed Encore Oil & Gas. He is joined by Eugene Whyms and geologist Graham Dore.*

Shell and ExxonMobil are to market *their interests in three North Sea producing assets – Auk, Fulmar and the Dunlin cluster.*

Venture Production (50%) reports that *the Gadwall oil field in North Sea block 21/19 has been brought onstream. Estimated proven and probable recoverable reserves are put at 6.4mn barrels.*

EUROPE

In the Revised National Budget for *2005 the average production of Norwegian crude oil (including NGLs) is expected to be 3.2mn b/d in 2005, approximately the same as last year. Gas sales in 2005 are estimated at approximately 80bn cm, up from 78.5bn cm in 2004. Gas sales are expected to rise towards a long-term level of 120bn cm/y from 2011. Investments are expected to amount to about NKr90 billion in 2005, including exploration funding, largely due to development of the Ormen Lange, Snøhvit and Kristin fields.*

Complete news update

The 'In Brief' news items in *Petroleum Review* represent just a fraction of the news we regularly publish on the EI website @ **www.energyinst.org.uk** via the 'News In Brief Service' link from the '***Petroleum Review***' drop-down menu. Covering all sectors of the international oil and gas industry, the News in Brief Service is a fully searchable news database for EI Members.

Why not visit the site to find out more about the latest developments and trends in your industry? Click on

www.energyinst.org.uk

Shell oil sands expansion plans

Shell Canada has filed regulatory applications to expand capacity at both the Muskeg River mine and Scotford upgrader project, part of the Athabasca oil sands project. The Muskeg River mine expansion plans include developing additional mining areas on the west side of lease 13 and on lease 90, adding another bitumen extraction train to the existing plant and a number of debottlenecking projects. This will increase capacity from 155,000 b/d to 300,000 b/d by 2010. In combination with the Jackpine mine approval received in 2004, this will provide Shell with regulatory approvals for mining developments encompassing all of lease 13 and lease 90, totalling 500,000 b/d of bitumen.

The Scotford upgrader expansion plan includes the addition of a third bitumen upgrading train which, along with debottlenecking of the existing facilities, will increase upgrading capacity to some 300,000 b/d.

Shell plans to further develop its leases in the Athabasca area by employing a continuous construction, 'building-block' approach. Each building block would be sized, at least initially, at approximately 100,000 b/d. As part of this strategy, Shell would start construction of the first 100,000 b/d mining expansion on lease 13 in 2006, concurrent with a similar-sized expansion of the Scotford upgrader and debottlenecking projects at both facilities, as outlined above. Opportunities to integrate new production trains with existing facilities will be considered where practical to reduce construction and operating costs. Additional building blocks, including both mining and upgrading expansions, would follow in due course. 'We believe that a building block approach will maximise construction efficiency as we grow our oil sands business,' says Clive Mather, President and Chief Executive Officer, Shell Canada. 'We're building from a solid base of oil sands experience and will leverage off that as we drive toward more than 500,000 b/d of production.'

EnCana sells GoM assets to Statoil

EnCana's US affiliates have reached an agreement to sell all of their interests in the Gulf of Mexico to Statoil for approximately \$2bn cash. The interests contain six significant deepwater discoveries including a 25% working interest in the Chevron-operated Tahiti discovery, one of the largest discoveries in the deepwater Gulf of Mexico to date (at 31 December 2004, EnCana had 41mn boe proved reserves booked for Tahiti).

The other five significant non-operated discoveries – Tonga (25% stake), Jack (25%), St Malo (6.25%), Sturgis (25%) and Sawtooth (25%) – are currently under appraisal. EnCana's Gulf of Mexico assets also include an average 40% working interest in 239 gross blocks comprising about 1.4mn acres.

ExxonMobil/Apache deal expanded

ExxonMobil and Apache are to expand their exploration and development activities in the western Canadian province of Alberta, building on a broader programme announced in 2004. Under the agreement, ExxonMobil Canada Energy will farm out its interest in approximately 650,000 acres of additional undeveloped property interests to Apache Canada over and above the more than 370,000 acres conveyed in 2004. Under the new deal Apache will also test additional horizons on approximately 140,000 acres of the property conveyed in 2004. Apache will have access to 1,234 sections under the new agreement.

In addition, Apache will drill and operate 145 new wells in both shallow and deep zones over a 36-month period with upside potential for further drilling. ExxonMobil Canada will retain a 37.5% lessor royalty on fee lands, while on Crown leasehold it will retain 35% of its original working interest for any production resulting from the drilling programme.

In May 2004, the two companies announced a programme of transfers and joint-venture activity aimed at increasing the realised value of their respective portfolios across a broad range of prospective and mature properties. These properties are located in West Texas, onshore Louisiana and the Gulf of Mexico Continental Shelf, as well as western Canada. Under that agreement, ExxonMobil gained deep gas rights to certain Apache properties in the Gulf of Mexico and onshore Louisiana, while Apache gained access to ExxonMobil properties in western Canada, the Permian Basin of West Texas and New Mexico.

The Norwegian Petroleum Directorate (NPD) has conducted a feasibility study of projects involving carbon dioxide (CO_2) injection for increased oil recovery on the Norwegian Continental Shelf. The conclusion is that, at the present time, CO_2 injection does not appear to be a commercial alternative for improved oil recovery for the licensees on the Norwegian shelf. For details, visit **www.npd.no**

The Norwegian government has *approved Statoil's plan for development and operation (PDO) of the Volve field in the North Sea, via the Sleipner A platform. Due onstream in spring 2007, recoverable reserves are put at 70mn barrels of oil and 1.5bn cm of gas.*

The Norwegian government has *approved Hydro's (25%, operator) plan for development and production (PDO) of the Fram Øst field in the North Sea via the Troll C platform. Production start-up is scheduled for October 2006. Recoverable reserves are put at 60mn barrels of oil and 2.9bn cm of gas.*

NORTH AMERICA

Imperial Oil, on behalf of the *Mackenzie gas project co-venturers, has announced a decision to halt project execution activities due to 'insufficient progress on key areas critical to the project. Substantial progress will need to be made prior to the start of public regulatory hearings, expected as early as late summer, to allow the project to continue.*

EnCana is to sell conventional oil and *gas assets producing approximately 6,400 boe/d, after royalties, to StarPoint Energy Trust for C$404mn ($326mn) before adjustments.*

Unocal is seeking prospective pur-
chasers for its Northrock subsidiary's western Canada crude oil and natural gas exploration and production assets, located in British Columbia, Alberta and Saskatchewan. The sale does not include the company's midstream and storage assets in Canada.

Devon Energy is reported to have *signed purchase and sale agreements for all of the US and Canadian properties that it is planning to divest. Proceeds from the assets sale are expected to total about $2.3bn.*

Total has acquired an additional 6.5% *stake in the Canadian Surmont leases in the Athabasca oil sands project, and*

First Egyptian gas deliveries

BG Group and partners Petronas and the Egyptian Natural Gas Holding Company (EGAS) have delivered first gas from the Simian Sienna fields offshore Egypt to the Egyptian LNG (ELNG) Train One at Idku. In addition, BG and its partners Edison International and EGAS have delivered first gas from Rosetta Phase Two to the Egyptian domestic market.

The BG-operated Simian Sienna fields are located in the West Delta Deep Marine (WDDM) concession in the Mediterranean Sea. The offshore facilities consist of eight subsea wells tied in to the existing WDDM gas-gathering network. In addition, there is a shallow-water control platform. The onshore processing facilities form part of the Idku gas hub, where the ELNG facilities are also located.

The BG-operated Rosetta field is located 60 km offshore Egypt. Under an amendment to the Rosetta gas sales agreement, the daily contracted quantity of gas production from Rosetta rises to 345mn cf/d from the current 275mn cf/d after 120 days from the first gas date. The Rosetta Phase Two development consists of an unmanned minimum facilities wellhead platform tied back to the existing Rosetta platform.

ELNG Train One is scheduled to produce its first LNG cargo before the end of June 2005. The entire 3.6mn t/y output of Train One has been sold to Gaz de France under a 20-year sales and purchase agreement. ELNG Train 2 is due to produce its first LNG cargo before the end of 2005. The BG-operated Sapphire field in WDDM will supply gas to Train Two. Sapphire is due to produce first gas in 3Q2005. The 3.6mn t/y output of Train Two has been sold to BG Gas Marketing for supply to the US initially, and later to Italy.

South Pars phases 4 & 5

Eni reports that it has successfully completed the South Pars phases 4 and 5 gas field development. The project included the construction and installation of two offshore wellhead platforms, the drilling of 24 gas production wells and the laying of two 32-inch diameter subsea pipelines to transport gas to shore, and the construction of a gas processing plant at Assaluyeh on the Persian Gulf.

The onshore gas processing plant will produce 20bn cm/y of gas, 1mn t/y of propane/butane and 80,000 b/d of condensates for export.

Eni is operator for the development of South Pars phases 4 and 5, with a 60% participating interest. Its partners are Petropars (20%) and NICO (20%), the latter on behalf of the National Iranian Oil Company under a buy-back contract signed in July 2000.

Akpo development

Nigerian National Petroleum Corporation (NNPC) has authorised Total, as operator, to begin developing the offshore Akpo field on oil mining licence (OML) 130, offshore Port Harcourt, Nigeria. Total holds a 24% interest in OML 130, partnered by NNPC, Petrobras and Sapetro.

The field development plan calls for 22 producing wells, 20 water injection wells and two gas injection wells, tied back to a floating production, storage and offloading (FPSO) vessel with a storage capacity of 2mn barrels. Akpo is due onstream in late 2008 and is expected to quickly reach peak production of 225,000 boe/d, of which nearly 80% (180,000 b/d) will be condensate. The condensate will be exported via a buoy located 2 km from the FPSO, while the gas will be piped 150 km to the Amenam/Kpono platforms, from where it will be sent to the Bonny liquefaction plant onshore Nigeria.

Record Independence umbilicals contract

Anadarko Petroleum and Dominion Oil and Gas have awarded Aker Kvaerner a $110mn subsea umbilical and production control contract for their Independence development in the Gulf of Mexico. A key element of the contract is the supply of approximately 180 km of steel tube umbilicals – reportedly the largest individual umbilical contract ever awarded.

The Independence project is located in up to 9,000 ft of water in the Atwater Valley, Lloyd Ridge and Desoto Canyon areas of the Gulf of Mexico. The project's subsea umbilical system is said to represent a 'step change in deepwater steel tube umbilical technology', using Kvaerner Oilfield Product's (KOP) carbon-fibre rod enhanced steel tube umbilical design. Delivery is scheduled to complete in 2006.

The Independence hub in Mississippi Canyon block 920 is the host for an initial 16 subsea wells belonging to the Atwater Valley Producers consortium, which includes Anadarko's Jubilee, Spiderman, Atlas, Vortex and Mondo NW fields; Dominion's San Jacinto field and Kerr-McGee's Meganser field. Future expansion is expected.

now holds a 50% interest alongside ConocoPhillips (operator). The first phase of production will start in 2006 and reach 27,000 b/d of bitumen. Phase 2 will involve the expansion of plateau production to 100,000 b/d by 2012. Further phases are also targeted.

Anadarko Petroleum reports that its *deepwater Genghis Khan well in Gulf of Mexico Green Canyon block 652 is a discovery, with open-hole logs indicating about 110 ft of high quality net oil pay in the lower Miocene formation and apparent additional pay uphole in the middle Miocene section. First production is expected in 2006, through a subsea tie-back to the nearby Marco Polo platform.*

MIDDLE EAST

Occidental Petroleum is understood to *have signed a heads of agreement to develop the Mukhaizna project, one of the largest oil fields in Oman. Occidental will act as operator, partnered by Liwa Energy.*

South Korea and Yemen are reported *to have signed a production sharing agreement (PSA) giving state-owned Korea National Oil Corporation (together with two private companies) the right to develop a Yemeni oil field with estimated reserves of between 50mn and 200mn barrels.*

Saudi Aramco reports that it has discovered *a new field capable of producing Arabian Super Light oil in the Central Region of Saudi Arabia. The Du'ayban-1 well will produce 3,300 b/d of oil, together with 3mn cf/d of gas.*

RUSSIA/CENTRAL ASIA

Surgutneftegaz is planning to invest *some 57.2bn roubles ($2.1bn) in a bid to increase hydrocarbons production during 2005. It aims to increase oil output to 1.3mn b/d, up 7.2% from 2004.*

Naftogaz Ukrainy (NAK) of Russia and *Shell have signed a cooperation agreement to carry out technical studies leading to joint exploration and production of hydrocarbons in an area of interest in the Dniepr-Donets Basin.*

Irish oil and gas company Dragon Oil *has encountered oil and gas while drilling on the refurbished LAM 10 platform in the Cheleken contract area offshore Turkmenistan in the deep reservoir zone of the LAM field, Zone 12, reports* Stella Zenkovich.

UK oil and gas continues decline

UK oil production fell by 13% in February to 1,716,160 b/d, continuing the past year's trend of declining production, according to the latest (May) Royal Bank of Scotland *Oil and Gas Index*. Gas production was also down by 13% on the year, at 9,781mn cf/d, although this partly reflected the mild start to the month. Combined oil and gas production was down by 5% on the month and 13% on the year, at 3,438,195 boe.

Tony Wood, Senior Economist with The Royal Bank of Scotland Group said: 'UK oil production continued its decline in February, despite the sustained period of high oil prices. With Opec unlikely to meet the medium-term call on supply by itself, high oil prices will continue to support the global investment environment. This should be positive for medium-term investment in the UK.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Feb 2004	1,972,891	11,220	30.89
Mar	2,006,160	11,787	33.72
Apr	1,964,905	12,181	33.36
May	1,778,979	9,218	37.72
Jun	1,776,246	10,192	35.21
Jul	1,758,312	10,292	38.15
Aug	1,621,582	8,585	42.99
Sep	1,526,692	8,726	42.92
Oct	1,630,230	9,921	49.66
Nov	1,734,630	10,395	42.88
Dec	1,817,724	10,834	39.55
Jan 2005	1,700,031	10,891	44.24
Feb	1,716,160	9,781	45.50

North Sea oil and gas production

Prospects for North Sea oil and gas

3i, a leading private equity and venture capital firm, recently published its 12-month review on the state of the North Sea's oil and gas industry, with proposals for its future survival. The new report examines the widespread changes that have taken place across the industry since *The Prospects for North Sea Oil and Gas – Challenge and Opportunity in a Maturing Province* study was published last year.

The report analyses the key trends that are transforming the North Sea oil and gas sector today – trends that have major ramifications for the majors, independents, contractors and European governments. It identifies five issues that create opportunities and challenges for the hydrocarbons industry and for investors:

- A slowdown in UK E&P mergers and acquisitions activity, driven by sustained high oil prices.
- A large fall in companies looking to enter the North Sea, with a switch to areas of greater geo-political risk.
- The need for new business and technical solutions to unlock financially stranded North Sea assets.
- A sharp improvement in prospects for supply companies with necessary strategic consolidation.
- The emergence of Norway as a country for private equity investment.

3i's head of Oil and Gas, Graeme Sword, states that, with an estimated 28bn barrels equivalent of oil and gas and a time horizon out to 2050 at least, the UK North sea oil reserve is 'just past half time' and represents a 'fantastic long-term opportunity for companies'. He points out that broad-based confidence has recently returned to the wider North West Europe Continental Shelf, as evidenced by 70 exploration and appraisal wells predicted for the UKCS this year and 40 for Norway. However, with the price of oil now predicted at approximately $50/b for the rest of the year, potential new entrants are finding it much harder to get a toe on the asset ladder. 'Big oil companies are generating great returns. However, the smaller, private companies face challenges to acquire assets on the exploration and production side, while on the service side margins are still tight, even though oil prices are sustained at a high level,' comments Sword. 'These sectors of the industry have to deliver new ideas, technologies and business models if they are to make the most of any opportunities.'

A full copy of the report can be downloaded from the 3i website at **www.3i.com**

ASIA-PACIFIC

***CNOOC's Luda (LD) 4-2 in Bohai Bay** has come onstream ahead of schedule. The field is producing 5,600 b/d of oil from seven wells. LD 4-2, together with LD10-1 and LD 5-2, is located in central Liaodong Bay of Bohai Bay, adjacent to the producing Suizhong 36-1 field.*

***The Indonesian government is under**stood to be planning to put out to tender 22 oil fields in an effort to increase domestic oil production.*

***Vietsovpetro, the joint venture** between state-run PetroVietnam and the Russian company Zarubezneft, has struck oil off the coast of southern Vietnam, in the Thien Ung 1X well 240 km off the coast of Vung Tao, writes* Stella Zenkovich.

***The Nepalese authorities are under**stood to have reported a 300mn cm natural gas discovery in the central and southern part of Kathmandu Valley.*

***Petronas Carigali reports that it has** installed the first Stratapac Separation Tool in its TK-54L well in Tukau Field, offshore Miri, Sarawak. Claimed to be the first such installation in the world, the tool is understood to have increased well production by approximately 400%. The tool is designed to be set inside the well tubing for sand control purposes.*

LATIN AMERICA

***Ecopetrol, Petrobras and ExxonMobil** are reported to have formalised the Tayrona contract with Colombia's National Hydrocarbon Agency (Agencia Nacional de Hidrocarburos, ANH) to explore 4.4mn hectares in Colombian Caribbean waters. It is understood to be the first such contract for exploration under the ANH's new contract model and it formalises the alliance between the three companies.*

AFRICA

***BP Egypt has extended two conces**sions in the Gulf of Suez – the Merged Concession Agreement (MCA) by 20 years and South Gharib by 10 years. The company is committed to invest at least $615mn over seven years in exploration and development activities, as well as renewing and upgrading the existing facilities and infrastructure across the Gulf of Suez. MCA and South Gharib production currently stands at just over 100,000 boe/d.*

Use of composite materials offshore

ABS has published guidelines for the use of composite materials on offshore structures, which is expected to facilitate industry consideration of alternatives to costly steel in the development of mooring systems and risers, according to Ernesto Valenzuela, Offshore Technology Development Manager, ABS. 'It is no longer a question of if, but when composite materials will take their first starring role in production from a deepwater hydrocarbon reservoir,' says Valenzuela. 'We have brought a comprehensive set of criteria to operators wanting to apply fibre reinforced plastics (FRPs) to their projects.'

'As projects become more complex and move into deeper waters, the topsides become heavier, the steel mooring systems and risers become longer and heavier, thus presenting serious challenges to project economics,' he explains. 'These challenges have spurred research into substitute materials that would do the job of steel, but at much lighter weights. Once thought of as an exotic material, composites and FRPs are gaining acceptance among operators'.

ABS plans to unveil its composite guidance in three stages. First is the release of criteria for FRPs in topside applications; second, criteria for carbon-fibre composite riser piping and joint application and; third, criteria for composites in cryogenic piping applications.

The ABS-issued *Guide for Certification of FRP Hydrocarbon Production Piping Systems* is reportedly the first publication of its kind from a classification society and is expected to become the primary source of composite guidance available to the offshore industry. The advantages of carbon-fibre composites over the basic production material of steel include higher strength-to-weight ratios, superior fatigue performance and corrosion resistance and better thermal insulation. Another advantage is a high structural damping characteristic that makes composite risers (or tendons) immune to vortex-induced vibration, a cause of severe fatigue damage to steel structures. Although weight is only one component in the complex considerations that make up an offshore production solution, weight reduction is among the most attractive benefits of composites.

Contracts for South Pars phases 9 and 10

Aker Kvaerner has won a $25mn project management contract for South Pars phases 9 and 10 offshore Iran, which will produce 2bn cf/d of gas. Aker Kvaerner will assist the national operator Pars Oil and Gas Company (POGC) in managing the $1.8bn total EPC (engineering, procurement and construction) contract for the phases 9 and 10 project. Aker Kvaerner has partnered up with Teheran-based, private engineering company Hirbodan for the contract.

Phases 9 and 10 of the project will comprise two unmanned wellhead platforms equipped with minimum production facilities, with two additional relief platforms, each bridge-connected to the associated wellhead platform. Two 32-inch diameter pipelines, with a capacity of 1bn cf/d, will transport the unprocessed offshore hydrocarbon production from each wellhead platform to the 2bn cf/d capacity onshore gas treatment plant in Assaluyeh. After treatment, the gas will be sent to the domestic gas network, while the extracted condensate will be stored in tanks for export.

Namibian Kudu concepts under study

Woodhill Frontier and J P Kenny, subsidiaries of Wood Group, have been awarded a contract by Energy Africa, a Tullow Oil group company, for the final concept selection and front-end engineering and design (FEED) for the proposed Kudu gas project off the coast of Namibia.

There are two main concepts being considered – direct subsea to beach (S2B) and the use of a floating production facility (FPF) for offshore processing. The FPF option will minimise the facilities and cost of the onshore gas terminal, compared to the subsea option. The subsea option also has significant technical challenges for the 180-km distance to shore. The FEED study is expected to last approximately six months.

Phase 1 of Kudu is due onstream in 2009 at an initial rate of 130mn cf/d, which will supply an 800-MW power plant at Oranjemund in Namibia. The NamPower-developed plant will supply both the expanding Namibian and South African markets. NamPower is a national utility company of Namibia, while Energy Africa, the operator of the gas field, is partnered by the National Petroleum Corporation of Namibia (Namcor).

UK

***According to a new report from Oxford** Economic Research Associates, wind farms will require £12bn in public subsidies – almost three times as much as nuclear power plants, which are claimed could provide the same amount of carbon-free electricity for £4.4bn.*

EUROPE

***Electricité de France (EdF) and Total** have increased their respective stakes in Total Energie, a company specialising in photovoltaic solar energy, to 50% each. Total Energie will now be known as TENESOL.*

***Repsol YPF and Gas Natural SDG have** reached an agreement for both companies to intensify their collaboration in the LNG business areas of exploration, production, transportation, trading and wholesale marketing.*

NORTH AMERICA

***Duke Energy is reportedly planning to** acquire natural gas storage and pipeline assets in southwest Virginia from AGL Resources for $62mn.*

***In a move to 'present a clear, strong** and unified presence in the global marketplace', ChevronTexaco Corporation is changing its name to Chevron Corporation, effective immediately.*

***ExxonMobil has posted a 1Q2005 net** income of $7.8bn, an increase of $2.4bn from 1Q2004, while Chevron has reported net income of $2.7bn for 1Q2005, compared with net income of $2.6bn in the year-ago period. ConocoPhillips reported a 1Q2005 net income of $2.9bn, compared with $1.6bn for the same quarter in 2004.*

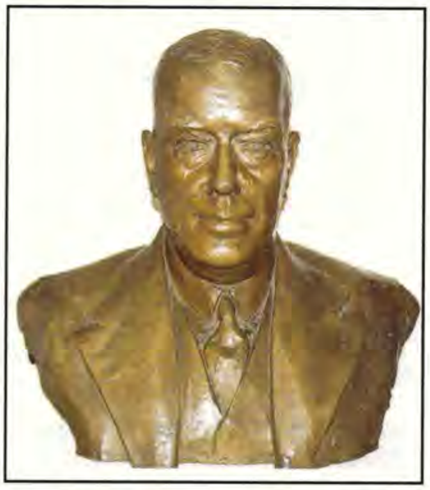
MIDDLE EAST

***Foster Wheeler has been awarded a** project management consultancy (PMC) contract by Abu Dhabi Gas Industries (GASCO) for the engineering, procurement and construction (EPC) phase of the third natural gas liquids (NGL) train project at Ruwais, Abu Dhabi, United Arab Emirates.*

***The Qatari authorities are reportedly** planning to delay new projects to convert gas into naphtha, diesel and other liquids for three years as the government wants to study the projects fur-*

EI Cadman award goes to Michel Contie

Michel Contie of Total UK has been selected as the recipient of the Energy Institute's (EI) 2005 Cadman Memorial Award. One of the EI's most prestigious awards, it commemorates the late Lord Cadman of Silverdale (see right), a former Chairman of the Anglo-Iranian Oil Company (now BP) and past President of the former Institute of Petroleum (now the Energy Institute).



The Cadman Award goes to Contie for 'outstanding services to the petroleum industry'. He will be presented with the award on 23 June in London.

Contie began his career as a research and development engineer, first in France and later in the US, involved in development of new technologies for deep offshore oil developments. He has held various operational and managerial positions within Total in France and other countries. In 1999, he became Senior Vice President of the French group's Latin America business, covering operations and new developments in that region. In 2000, he was given the task of leading Total's UK business, which is headquartered in Aberdeen, since when he has become very well known in North Sea circles and a prime mover of change at the UK Offshore Operators Association (UKOOA), of which he was President in 2002.

Contie has presided over huge change at Total's North Sea business in his quest to ensure it remains relevant to headquarters in Paris. The jewel in the crown remains the highly successful Elgin/Franklin high-pressure, high-temperature gas/condensate development, while the core, but ageing, Greater Alwyn business continues to make a valuable contribution.

Contract for Italian LNG terminal

Qatar Petroleum, ExxonMobil and Edison have awarded Aker Kvaerner a $900mn contract for engineering, procurement and construction management services associated with development of the Isola di Porto Levante LNG terminal, to be located offshore the coast of Italy in the North Adriatic Sea. The contract comprises engineering, procurement and construction management of the concrete gravity based structure, LNG storage tanks and topside regasification facilities.

The terminal will have a total storage capacity of 250,000 cm and will be equipped with a berthing/mooring system for offloading LNG, designed to accommodate ships delivering up to 150,000 cm of LNG. Gas for the project will be sourced from Qatar's giant North field, which has recoverable resources of more than 900tn cf (25.5tn cm). The facility is expected to supply 8bn cm/y of gas to the Italian energy sector.

BBC seeking a company for new TV programme

The BBC's Business Programmes Unit is looking for a company that will benefit from top-flight advice. Following on from the success of programmes like 'Back to the Floor' and 'I'll Show Them Who's Boss', this time the BBC wants to concentrate on 'people issues and communication problems', rather than business strategy. The plan is to bring in a renowned expert to assess the situation and provide solutions.

The BBC is looking for a company with between 20 and 150 employees. The type of business and its location aren't important. What matters is that the managing director feels there's a problem that needs sorting out.

For more information, contact Kate Murray in confidence on t: +44 (0)20 8752 7345 or e: **kate.murray@bbc.co.uk** *ther in order to avoid problems with infrastructure, shipping and contractors, and to ensure that gas resources are developed at a sustainable rate.*

RUSSIA/CENTRAL ASIA

BTC Company, operated by BP, has *started filling the BTC head pump station at the Sangachal terminal, marking the first linefill phase of the Baku-Tbilisi-Ceyhan (BTC) oil export pipeline. The first stage of linefill and operational testing is in anticipation of first oil into the Heydar Aliyev BTC main export pipeline as* Petroleum Review *went to press.*

ASIA-PACIFIC

Shell Gas & Power has announced the *start-up of the Hazira LNG receiving terminal, located near Surat in the state of Gujarat in north-west India. The Hazira terminal received its first cargo on 17 April, which arrived from Australia's North West Shelf project in which Shell has a 22% stake. The facility is capable of receiving up to 2.5mn t/y of LNG, although it has future expansion potential up to 10mn t/y.*

CNOOC is to develop a 2mn t/y LNG *terminal on Hainan Island in southern China, the first phase of which is due for completion by 2009. Plans are to expand capacity to 5mn t/y by 2015.*

AFRICA

Penspen has signed a contract with *Nigerian National Petroleum Corporation (NNPC) and Sonatrach of Algeria for the feasibility study for the Trans-Saharan gas pipeline. The pipeline is proposed under the NEPAD initiative to connect to gas resources in Nigeria and Algeria and transport them to consumers accessible from the pipeline along its route and at its terminal point on the Mediterranean coast of Algeria.*

The National Oil Corporation of Libya *(NOC) and Shell have reached a long-term agreement covering the rejuvenation and upgrade of the existing LNG plant at Marsa Al-Brega on the Libyan coast, together with the exploration and development of five areas located in the heart of Libya's major oil and gas producing Sirte Basin. The Marsa Al-Brega LNG plant upgrade will increase plant output from 0.7mn t/y to some 3.2mn t/y. Subject to gas availability, Shell will also undertake jointly with NOC the development of a new LNG facility.*

Shell posts record 1Q2005 profit

Shell has reported record first-quarter profits of \$5.5bn (£2.9bn) despite a sharp fall in oil production as output declined from some of its ageing fields. The company expects to return between \$13bn and \$15bn to shareholders over the course of 2005.

Chief Executive Jeroen van der Veer outlined the group's objective of lifting its reserves replacement ratio back above 100% over the next five years. However, he ruled out achieving this with the help of acquisitions, stating that the current high oil price made takeover deals too expensive. The company cut its proved reserves by a quarter in 2004, while replacing just 19% of oil production with new discoveries.

Although production from new fields in the North Sea, Gulf of Mexico and Malaysia more than offset a decline in output from older fields, oil production fell by 8% in the period to 2.14mn b/d. Overall hydrocarbon production, including gas resources, fell by 2% to 3.85mn boe/d.

Shell claims it remains on track to implement sweeping corporate reforms prompted by the recent reserves fiasco, having unified its UK and Dutch entities into one London-listed company with a single board in July.

Record first-quarter profits for BP

BP Chief Executive Lord Browne forecast that world oil consumption growth and limited spare production capacity would keep the price of oil above \$40/b for the rest of 2005, as he reported a 29% increase in first-quarter profits to a record \$5.5bn (£2.87bn). He also reported that the strong oil price, combined with strong refining margins and a \$535mn gain on BP's sale of its stake in the Ormen Lange field in Norway, had helped BP's replacement cost profit increase from \$3.5bn to \$5.5bn, on total revenues that had risen by 2% to \$79bn in 1Q2005. Shareholders received in excess of \$4bn in dividend payments and share buy-backs.

Buoyed by an average oil price of \$48/b for the quarter, BP's E&P division increased profits by 56% to \$6.5bn, despite production remaining flat at 4.1mn b/d. The group's refining and marketing arm increased profits from \$920mn to \$1.42bn, largely due to higher refining margins (fuel retailing margins were lower because of the increase in crude prices).

Lord Browne also indicated that the group remained confident about doing business in Russia, despite its joint venture TNK-BP facing a large tax bill there. He stated that BP was not liable for any back taxes pre-dating the joint venture and said that following a meeting with President Putin he felt 'reassured' that TNK-BP would 'not be positively discriminated against'. Lord Browne also predicted that the eventual tax settlement would be significantly lower than \$1bn.

Recent European Union developments

Andris Piebalgs, the European Union (EU) Commissioner for Energy, has announced that energy conservation will be his top overall policy priority for his five-year term, not the issue of developing new energy sources, reports *Keith Nuthall*. The European Commission (EC) will this year launch a 'European Energy Efficiency Initiative', he said, setting the EU 'an ambitious but realistic and achievable target' to save, by 2010, the equivalent of 70mn t/y of oil – saving the EU 15bn annually. Increasing gas liberalisation is Piebalgs' second priority, with a progress report coming this winter.

In other EU news:

- **A detailed cooperation agreement struck between the EU and Russia involves an 'intensification' of joint work on energy matters, especially regarding the sustainability of and reliability of supplies. Both sides will combine efforts to ensure the safety of transport of gas and oil, and Russia has committed itself to 'gradual and progressive reform' of its gas sector, abiding by an existing strategy to 2020.**
- **With the accession of Bulgaria and Romania to the EU expected in 2007, the EC has confirmed exemptions from EU energy legislation to be enjoyed by these countries. Bulgaria can delay complying with EU rules on minimum crude oil and petroleum stocks until December 2012, Romania until December 2011. Both countries can delay introducing minimum excise duty rates for unleaded petrol until January 2011, and for motor fuel gas oil until January 2013.**
- **The European Investment Bank (EIB) is planning to lend Italgas up to 200mn to renovate, rehabilitate, modernise and expand its networks.**
- **The ecology and mineral resources (including oil and gas) at the fringes of Europe's undersea continental shelf are to be assessed by a 15mn EU study called HERMES. For more details, visit** www.eu-hermes.net

UK

***Dave Blakemore is the newly** appointed President of UKPIA (the UK Petroleum Industry Association).*

EUROPE

***The German government was to** shut down the Obrigheim nuclear power plant in southern Germany in May as part of a wider plan to close all 29 of its nuclear facilities by the year 2020.*

***Companies selling lubricants in the EU,** including hydraulic oils, chain saw oils, two-stroke oils and greases, can now apply for a EU eco-label if their product has low environmental impact, reports* Keith Nuthall.

***BASF and Shell Chemicals are to sell** their 50-50 joint venture Basell, one of the world's leading manufacturers of polyolefins, to a consortium led by New York-based Access Industries together with The Chatterjee Group. The sale price will total 4.4bn, including debt.*

***Italian gas provider Enel's acquisition of** Slovakian electricity producer Slovenske Elektrarne has been approved by the EC, writes* Keith Nuthall.

***UK company Kaneb Terminals has** acquired the Amsterdam terminal and refinery assets of Esha (previously Smid and Hollander) for an undisclosed sum.*

***Political pressure from the EC has per**suaded France's Total and Sasol Wax International of Germany to abandon a planned petroleum-based wax joint venture, reports* Keith Nuthall.

***Foster Wheeler Energy has been** awarded a study contract by Preem Petroleum of Sweden for fuel oil upgrading at its Gothenburg and Lysekil refineries.*

***Shell and Bechtel have agreed to sell** InterGen and 10 of its power plants in the UK, the Netherlands, Mexico, the Philippines, China and Australia to a partnership between AIG Highstar Capital and Ontario Teachers' Pension Plan for $1.75bn. Excluded from the sale are InterGen's assets in the US, Colombia and Turkey, which will be reorganised prior to financial closing and retained by Shell and Bechtel pending further review.*

Autogas is not an auto-choice

New research from independent market analyst Datamonitor shows that Europe has significant potential for increased utilisation of cleaner burning and efficient automotive LPG (autogas). Existing levels of LPG penetration and availability of supply are reportedly sufficient to prevent any major barriers to wider-spread use, although stronger governmental fiscal incentives of the type seen in other markets are required to help accelerate the process.

The world's seven largest autogas markets account for a disproportionately high level of demand given their sizes. Collectively, Australia, Italy, Japan, Mexico, Poland, South Korea and Turkey account for more than 68% of global autogas demand, yet just 15% of the world's car fleet, 7.4% of population and 22% of global GDP. One of the key reasons for the high level of autogas use in these markets is the elevated degree of governmental support in the form of favourable tax incentives aimed at encouraging autogas use. The reasons for governments to encourage autogas use are well documented, with emissions and efficiency gains from autogas comparing favourably with both petrol and diesel.

A prime example of how favourable tax incentives have catalysed autogas use is Australia, according to Datamonitor Energy Analyst Andrew Hill. 'Excise tax is not currently levied on autogas and the 10% general sales tax was only levied on autogas in 2000. As such, autogas costs around 60% less than petrol and diesel on the forecourt.'

Further examples of the incentives offered by the Australian government include grants to assist with conversion costs, Hill says. 'The attractive fiscal incentives on autogas offered by the Australian government mean that the costs of conversion can be recovered in significantly less time than in many other markets. The effect of these tax incentives is clear, given that per capita autogas consumption in Australia is the second highest in the world at 113 litres annually, second only to South Korea's 144 litres.'

The established nature of the Australian autogas market means that the decision made in 2003 to phase in a 12.5 cents/litre tax on autogas is unlikely to significantly curtail consumption, particularly given that the tax will be introduced over a 5-year period from 2011. 'Although the decision to levy the tax was unpopular amongst Australian motorists, the blow was softened by the extended phase in, the long notice period and the use of a A$1,000 cash back grant to purchasers of new autogas vehicles during the phase in period,' Hill says.

Although the potential for increased autogas use theoretically exists in all European markets, some countries have greater potential in the short term than others given their existing use of LPG and indigenous production levels, states Hill. 'Countries such as the UK, Germany and Denmark have by far the greatest potential given their high levels of LPG use outside of the automotive sector and, more importantly, their minimal import requirements. Conversely, markets such as the Netherlands, Ireland, Portugal and Spain have slightly less, although still significant, potential as a result of their extensive use of LPG in other sectors, though supply availability may constrain autogas development in the short term.'

Datamonitor's research found that markets such as Finland and Sweden, where use of LPG is minimal, will be the most difficult to develop autogas use in, although by no means impossible given the right governmental and industry support.

Biofuels bioremediation in the Philippines

D1 Oils, the UK-based producer of biodiesel, has announced an agreement between its subsidiary D1 Oils Asia Pacific and Atlas Consolidated Mining and Development Corporation, a leading Philippines mining and resource company. The two companies are to collaborate on a major project in the Philippines to rehabilitate land previously degraded by mining through the cultivation of *jatropha*, D1 Oils' feedstock of choice in the production of biodiesel.

President of the Philippines, Gloria Macapagal Arroyo, planted the first seedling at the project site in Toledo, Cebu Province. President Arroyo also supports D1 Oils' plans to intercrop *jatropha* on coconut plantations in the Philippines to help meet the government's targets for the use of biofuels.

The project will use bioremediation, a means of restoring soil that has suffered erosion and pollution in the mining process, by using *jatropha* to help replace lost nutrients. *Jatropha* was chosen not only due to its restorative qualities but also, and more importantly, because of its advantages as a biofuel feedstock. The first stage of the project is a five to seven hectare model farm and demonstration facility. The ultimate objective is to plant *jatropha* on 7,000 hectares of degraded land to produce fuel for power generation for off-grid mining facilities.

NORTH AMERICA

***Duke Energy is reportedly planning to** acquire rival power company Cinergy in a stock deal worth $9bn that will create one of the largest power generators in the US. The new company would have 5.4mn retail customers, more than $70bn in assets and about $1.9bn in annual profit on $27bn in annual revenue. The proposed merger would allow Duke to complement its gas-fired operations in the Midwest with Cinergy's coal-fired plants.*

***Unocal is conducting a non-binding** open season to secure expressions of interest in firm gas storage services for 6bn cf of capacity at a facility to be developed on its Windy Hill property in Morgan County, Colorado. If built, this would be the first-ever bedded salt underground natural gas storage facility in Colorado, claims the company. Phase 1, expected to be in operation by early 2008, and will offer 3bn cf of working gas capacity.*

***BP has announced plans to invest more** than $130mn on new clean diesel facilities at its Whiting, Indiana refinery. With the addition of a new distillate hydrotreater (DHT), the refinery will produce some 36,000 b/d of ultra-low sulphur diesel fuel that meets or exceeds all on-road diesel regulations in the US. The US EPA (Environmental Protection Agency) will require 15 ppm sulphur on-road diesel production beginning in June 2006, at which time 80% of the BP Whiting refinery's on-road diesel fuel must meet the new EPA specification. By January 2010 all on-road diesel must contain no more than 15 ppm sulphur. Off-road diesel transitions to the 15 ppm specification in 2010, and locomotive and marine diesel follow in 2012. The Whiting refinery currently produces approximately 3.4mn gallons of diesel fuel per day.*

***Valero Energy, the largest independent** oil refiner in the US, is to acquire rival Premcor. The $6.9bn cash and stock deal will add four refineries and 790,000 b/d of throughput capacity to Valero's portfolio.*

***Honda Motor Company is offering a** natural gas vehicle with its own home refuelling machine at dealerships in California. The company claims that this will be the first time that consumers can buy the vehicle in a dealership, leasing a refuelling machine at the same time. Honda expects to sell about 300 of the vehicles this year at 17 dealerships in north and south California.*

Saudi Aramco outlines three megaprojects

Isam A Al-Bayat, Saudi Aramco's Vice President of New Business Development, recently provided details on three Saudi Aramco megaprojects – the Rabigh integrated refinery and petrochemical complex; a grassroots export refinery; and a refining and petrochemical project at Ras Tanura & Ju'aymah – that represent investment opportunities worth billions of dollars. The projects, Al-Bayat explained, are spearheaded by the company's New Business Development organisation, which was established in early 2003 with the mission of identifying business opportunities that leverage Saudi Arabia's competitive advantage with respect to feedstock and fuels.

The Rabigh project was started in May 2004, when Saudi Aramco and Sumitomo Chemical of Japan signed a memorandum of understanding to develop the existing 400,000 b/d Rabigh refinery into an integrated refinery/petrochemical complex. The new complex will integrate the refinery with a world-scale high olefins FCC (fluid catalytic cracker) and ethane-based steam cracker, which will be coupled with downstream derivative units that will produce 2.4mn t/y of secondary petrochemicals. The project is scheduled to come onstream in 3Q2008.

The second project is a proposed 400,000 b/d export refinery, the cost of which would be between $4bn and $5bn.

Saudi Aramco is also looking into the possibility of integrating petrochemicals production with the Ras Tanura refinery and Ju'aymah industrial area feedstocks. Ras Tanura refinery currently consists of a 325,000 b/d hydrocracking refinery and a 200,000 b/d condensate splitter. The proposed integration would include a large ethane/naphtha-based cracker, an aromatics recovery complex, and complementary downstream derivative units to produce new secondary petrochemicals. The total project cost will be about $6bn.

Delivering a low carbon economy

Although improved technology and lower carbon fuels can make a substantial contribution to meeting carbon dioxide (CO_2) reduction targets, a significant change in consumer behaviour will be required for the UK to make the transition to a low carbon economy and meet the UK government's 2050 CO_2 reduction targets. This was one of the main conclusions of a recent conference and workshop held by the UK Petroleum Industry Association (UKPIA) in association with the Energy Institute (EI).

The UK government's CO_2 reduction targets are for the UK to be on the path to a 60% reduction by 2050, with real progress by 2020. The reductions are based on 1990 levels of emissions. Under the global Kyoto Protocol the government is committed to a 12.5% reduction in greenhouse gases by 2008/2012 and a national goal of CO_2 reduction of 20% by 2010.

UKPIA Director General Chris Hunt commented: 'We were greatly encouraged by the level of interest in this conference, which was heavily oversubscribed. On the day, we heard some thought provoking views from the presenters and had a constructive debate in the two workshop sessions, looking at the roles of technology/energy efficiency and behavioural change in reducing CO_2 emissions. Clearly a lot can be achieved. The challenge is for the government elected on 5 May 2005 to frame clear consistent policy and work with industry and other organisations to develop solutions. Above all, consumers need to understand that technology can only take us so far and so there is a requirement for clear advice on a range of consumer energy choices that can start to make a difference.'

Speakers at the conference encompassed a wide range of organisations. Tony Grayling of the Institute for Public Policy Research expressed the view that the severity of the situation meant that the UK should aim for a 20% cut in CO_2 emissions by 2010 and 40% by 2020 (from 1990 level), but warned that reductions would not be achieved unless government, industry and consumers took responsibility.

Stephen Joseph of Transport 2000 said experience indicated it was possible to change behaviour and encourage less carbon-intensive travel. John Mumford of BP said consumers needed to be made more aware of their personal energy consumption in the home, in transport and even associated with the food they ate. Richard Tarboton of the Energy Savings Trust considered that influencing car buying and usage remained a key challenge, a theme echoed by Simon Barnes of the Society of Motor Manufacturers and Traders, who pointed out that CO_2 reduction had become a bigger influence upon fleet buyers than private buyers. Reduction could come from a number of areas including consumer behaviour, driver education, managing road transport demand, and improved vehicle and fuel technology.

A conference summmary and copies of slides are available on the UKPIA website at **www.ukpia.com** under 'Publications', from where a pdf format copy of the recent UKPIA report *Delivering a low carbon economy* can also be downloaded.

US researchers have developed a fuel *cell that reportedly enables bacteria to create four times more hydrogen directly from biomass than has so far been generated by fermentation, writes* Monica Dobie. *The Pennsylvania State University experiment used a new electricity assisted microbial fuel cell requiring no oxygen.*

MIDDLE EAST

The Iraqi government wants to build *two new refineries to better handle oil revenues, reports* Stella Zenkovich. *The new refineries would practically double Iraq's production capacity for gasoline and other oil products to about 1mn b/d, up from the 500,000 b/d of capacity currently provided by three ageing refineries.*

ASIA-PACIFIC

China-based CMC International *Tendering Corporation has contracted German company RWE SCHOTT to bring electricity to 26 villages in the remote Gansu Province. The project is being realised as part of the Chinese government's 'Brightness Programme', which is bringing electricity to extremely remote and currently unelectrified villages through the establishment of independent village 'minigrids'. These local grids will be powered by local hybrid diesel/solar power plants, 90% of whose energy output will be solar-based.*

The Indian government is reportedly *planning to build three tanks for the storage of emergency crude oil stocks. The tanks, two at or near Mangalore and one at Visakhapatnam, will be capable of supplying up to 5mn t/y of oil. The facilities will be managed by Indian Strategic Petroleum Reserves, a wholly owned subsidiary of IOC.*

The Indonesian government is *reportedly planning to put out to tender a number of infrastructure projects in its domestic energy sector, including gas piping and power plants. Minister of Energy and Mineral Resources Purnomo Yusgiantoro stated that tenders for gas piping projects would be hosted by the Oil and Gas Executive Body (BP Migas), while power plant projects will be offered by state-run electricity company PT Perusahaan Listrik Negara (PLN). The government is keen to secure greater participation by private investors in the development of Indonesia's energy sector.*

Tesco to sell bioethanol fuel blend

Tesco is reported to be the first major fuel retailer in the UK to sell standard unleaded petrol containing 5% bioethanol, a renewable product which delivers lower emissions of the greenhouse gas carbon dioxide. The new fuel is being rolled out at more than 150 Tesco service stations in south-east England. The bioethanol is produced in Brazil from sugar cane and shipped to fuel supplier Green*ergy*'s plant on the Thames Estuary, where it is blended and then delivered to the Tesco forecourts.

Lucy Neville-Rolfe, Tesco Group Director of Corporate Affairs said: 'We are always looking at ways to pioneer new products and bioethanol blended unleaded petrol is a win-win for customers and the environment. It doesn't have any adverse affects on a vehicle's performance, but does have a better effect on the environment.'

Andrew Owens, Chairman of Green*ergy* Fuels continued: 'Not only are these premium quality fuels delivering the performance drivers seek – but they also meet all manufacturers' warranties whilst delivering significant benefits for the environment... Sugar cane is the most tried and tested method of producing ethanol, but it can be derived from sugar beet. Currently there is neither the volume nor the facilities in the UK for producing the amounts of ethanol required by Tesco. However, we are exploring British bioethanol sources with our suppliers and the farming community, with a long-term aim to source locally as much as possible.'

The south-east of England accounts for 40% of the UK's unleaded petrol market and Tesco expects to use around 80mn litres of bioethanol this year, which will be blended into 1.4bn litres of unleaded petrol. Since 1 January 2005 the government has offered a 20p per litre duty incentive on ethanol included in unleaded petrol. At a 5% inclusion this equates to 1 pence per litre for biopetrol. Although the raw material and production cost of ethanol is greater than unleaded petrol, the duty incentive means that ethanol can be used for the same price as unleaded fuel.

US focus on hydrogen fuel technologies

Hydrogen fuel technologies are one of the areas of focus in recent alternative fuels initiatives in the US. The Bush Administration has completed a number of high-level hydrogen industrial road mapping sessions at the US Department of Energy and has launched a hydrogen-fuelled 'Freedom Car' programme. Meanwhile, Senator Hillary Rodman Clinton has just secured funding out of the Department of Defense appropriations on behalf of General Motor's delivery of the first hydrogen fuel cell truck to the US Army. Hydrogen fuel technologies are currently being developed for automobiles, with California Governor Arnold Schwarzenegger leading the way with his hydrogen-powered Hummer vehicle. In some areas of the US, commercial buildings have been modified to use hydrogen power plants, and hydrogen power units are producing electricity in various other commercial applications such as research labs and computer power backup units.

Following on from these developments, Energy Ventures Organization reports that it has acquired funding for advancement in various research and development technology projects. 'We are going to educate the public first, the new hydrogen economy will soon be here,' stated President and Director of Energy Ventures Organization, Conrad Vergara. 'We will become a leader in common home and residential "zero pollution energy solutions" (ZPES). Hydrogen is the most simple and common element in the universe. Although never found naturally in pure form, it can be produced from a host of available resources, including water, natural gas, coal biomass, municipal solid waste, or scrap tyres.'

Energy Ventures Organization has developed a hydrogen producing prototype and now, with the collaboration of Apollo Alternative Fuels Company and its existing technology, will focus on continued R&D to produce an up-scaled unit that will provide the daily energy requirements to power a standard household on a daily basis along with enough fuel to operate the family automobile.

Energy on your screen

Trading has moved from pits to PCs. Today, anyone can view the widest variety of markets and products on a computer screen. Sean Martin, *a consultant with Patsystems, looks at the rise of electronic trading and its impact on the energy sector, and considers technology options for petroleum.*

Think of trading in the 1970s and 1980s. Long before the Internet and e-commerce, long before personal computers were on every desk and in every home, trading was a very different affair. Business was conducted on 'open outcry' floors where markets were driven by shouts and gestures, and where profits depended less on technology than a frenzy of face-to-face buying and selling. In short, manual processing ruled.

Today, however, electronic trading wears the crown – but it has been a long abdication for the pit trader. As in other areas of the financial sector, new technology has been resisted because it challenged traditional roles and practices. Although Nasdaq has led a strong pro-electronic lobby since the 1970s, and early adopters such as OM Click (1985) and the Sydney Futures Exchange (1989) have added to the momentum, it's been a slow revolution for screen-based trading. For instance, Liffe launched an automated system in 1989 (but did not go fully electronic until 2000), the Chicago Mercantile Exchange introduced Globex in 1992, and the Hong Kong Futures Exchange went partially electronic in 1996.

Enter the Internet

In the long run, the benefits of electronic trading have been difficult to resist – and in the last few years the pace of change has quickened. Better price discovery and speed of delivery, extended opening hours, wider distribution channels and the promise of straight-through processing – these are just some of the advantages of the electronic model. The tipping point, of course, was the arrival of the Internet, which made e-commerce possible and turned computer screens into global marketplaces.

Whatever the product, whatever the commodity, it's yours to trade online if you have the right software. As a result, since the late 1990s, a new breed of independent software vendors (ISVs) has built a thriving industry on the demand for electronic trading tools. Today, there are almost as many electronic solutions as there are stars in the sky, as well as a huge variety of professional and retail traders. Witness the rise of 'day traders', for example, who owe their existence to the levelling effect of new technology. Want to be a trader? Want to trade futures, options, equities or foreign exchange? All you need is a front-end and exchange connectivity.

Energy goes electronic

Energy is one of the last bastions of the pit trader, but times are changing. The mature markets for oil and gas, as well as the emerging markets for power, emissions and weather trading, are now following the example of other derivatives markets and switching to electronic trading.

Consider the International Petroleum Exchange (IPE) and the New York Mercantile Exchange (Nymex). The IPE has been riding two horses for some time, with open outcry and screen-based trading existing side by side, but it is now fully electronic having closed its oil and gas trading pits in April 2005. Equally, although still predominantly open outcry, Nymex has seen rapid growth in its electronic business and recently announced record volumes on its Access electronic trading platform. How long before it, too, abandons trading pits?

Issues and opportunities

No doubt about it – energy is hot. The collapse of Enron may have sent shock waves through the oil industry and cast a shadow over electronic initiatives, but confidence has recovered and energy is now back in favour – particularly since investors have taken a beating in equity markets. Deregulation has been counterbalanced by improved risk control, greater transparency, and more rigorous and resilient trading systems. In other words, it's a good time to consider online energy trading. Indeed, recent research by Accenture suggests that the global online energy market will be worth over \$8tn by 2007.

Rising oil prices have helped energy to trounce other funds in recent years. To take one example, Brent crude traded at under \$20/b in 2001 but passed the \$55 mark in April 2005. Although it's easy to be seduced by rising prices, there are no guarantees of continued spikes. Only those with very short memories and thick skins will fail to remember the spectacular demise of technology, media and telecommunications stock five years ago. The thing about bubbles is they burst, sooner or later.

However, there is every sign that rising demands from the emerging economies such as India and China, combined with limited supply, will keep the market buoyant. In fact, one optimistic report from Goldman Sachs suggests that we may be entering a 'super spike' period and that the price could top \$100/b. In addition, there are new opportunities as a result of 'green trading', with different derivatives being linked to give traders more choice. This, of course, is grist to the hedge fund mill, and one reason why the energy sector is attracting such attention from the alternative investment sector. According to the latest estimates, there are more than 300 energy-trading hedge funds (see p14).

But let's not forget geopolitics – a familiar backdrop to the oil industry. Prices are extremely susceptible to political frictions and policy changes, while slow economic growth and the possibility of global recession must also be considered. Even so, the most informed view is that demand will remain strong. China for one, which consumes 6mn b/d of crude – almost 10% of global consumption – is expected to be using 8mn b/d by the end of 2006.

Technology: the basics

If you want to trade oil contracts, whether as a seasoned professional or as a novice day trader, you have a wealth of technology choices. The first step is to find a system that meets your basic demands, which in all cases should include speed and reliability.

Speed and execution are fundamental. You need swift pricing, hedging and report information, and the ability to quickly and easily enter and exit positions. Any compromise on response times could mean the difference between profit and loss. Moreover, you don't want to lose your connection at a critical moment; so if you're a committed all day-trader with a high turnover, it's worth paying for a dedicated connection. Although there is no such thing as 100% reliability, an erratic connection is useless. In electronic trading, timing is everything.

If speed is your top priority – perhaps because you're a high-volume trader concentrating on very specific contracts – you may be less concerned with functionality. In which case, consider sacrificing charts and other analytical tools because they absorb vast amounts of memory, and keep your system lean and agile. If you do want analytics – maybe because you're a strategic trader with complex plans – make sure they're easily accessible from the trading screen. Analytical tools, such as 'what if' scenarios, are similar to your 'favourites' – they're valued items that should be no more than a keystroke away.

Ease of use is another important consideration. You may have a wealth of features and functions, you may have powerful charts and reporting tools, but can you navigate quickly and easily? Ideally, you should have everything you need on one page. Some systems require you to toggle between pages to perform different functions, which makes it more difficult to execute trades as well as keep an eye on your account positions.

If you want a fully supported 'professional' trading environment, an arcade may be the solution. Arcades have become increasingly popular as electronic trading has taken off. They provide all the hardware and software you need and allow you to share knowledge and strategies with your co-workers. The typical cost of renting a desk is between £1,000 and £2,000 a month.

The power to trade

Little more than a decade ago, there were virtually no commercial packages for would-be traders, no off-the-shelf solutions, no ready-made routes to exchanges. Now, thanks to the rise of independent software vendors, anyone with a PC has real trading power. Patsystems, Trading Technologies, FFastill and Easyscreen are just a few of the many vendors that provide software for derivatives traders.

Take Patsystems as an example. Founded in the mid-1990s, the company was one of the first to bring high-performance trading to the ordinary person in the street. Patsystems provides global connectivity through a range of front-ends and a trading platform that includes transaction servers, exchange-specific adapters, FIX gateways, and comprehensive customer support and risk administration.

The front-ends are J-Trader, a general-purpose application that is one of the most widely distributed in the derivatives industry; Pro-Mark, a new application designed specifically for high-volume professionals; and IQ-Trader, another new trading tool, targeted at 'strategic traders' who like to plan and carefully engineer their trades with the help of charts and other intelligent tools.

With Patsystems' front-ends, you can trade the IPE, Nymex, and the Tokyo Commodity Exchange (Tocom). As well as energy markets, 30 other leading derivatives exchanges are also available from the same screen. Patsystems has conformed to the latest version of the IPE application program interface and was one of the first independent software vendors to connect to Tocom. Through Nymex NEON, an electronic interface introduced by Nymex in October 2004, Patsystems provides access to electronic and open outcry exchanges. It also provides a software bridge, called X-Link, which allows you to connect to exchanges where you are not a member.

So what can you trade? All types of futures contracts and calendar spreads, plus crude spreads, crack spreads (including Nymex 3-2-1 crack spreads) and product arbs. The latter, which include heating oil and gas oil, are traded using a multi-exchange legging tool. You have access to all exchange-supported order types, plus 'synthetics' such as synthetic stops, and you have the option of floor order routing (through an application called screen2pit) as well as electronic access.

If you are moving to screen-based trading for the first time, front-ends such as J-Trader, Pro-Mark and IQ-Trader give you the functionality and power to succeed in every type of derivatives market, including the energy sector. However, as in all trading, reward is not without risk, profit not without loss. Technology is only a means to an end. It has certainly brought trading to the masses, from day traders at home through to arcade teams and professionals in investment banks; but it is people who control technology. Ultimately, no matter how good your trading system is, success depends on human judgement. In that sense, although we have taken trading out of the pits and off the floors, manual processing – or, more accurately, mental processing – is still very much part of the trading landscape.

From pit to screen

The rise of energy contracts on Nymex and IPE

- 1978 – Nymex (New York Mercantile Exchange) begins trading energy futures and options.
- 1980 – IPE (International Petroleum Exchange) founded.
- April 1981 – IPE launches gas oil futures.
- March 1983 – Nymex launches light sweet crude futures.
- Late 1980s – IPE ring trading ends, pit trading begins.
- June 1988 – Brent crude futures launched. Rising volumes lead to growth of other instruments, such as swaps and options.
- April 2001 – ICE (Intercontinental Exchange) buys IPE on condition that it will become exclusively electronic.
- September 2001 – Nymex launches its own Brent contract.
- November 2004 – IPE introduces new trading hours, extending electronic trade and postponing the start of open outcry Brent trade until 2pm. On the same day, Nymex opens an open outcry Brent pit in Dublin.
- April 2005 – IPE abandons open outcry and becomes fully electronic.

Hedging your bets

Maria Kielmas *takes a closer look at the role of hedge funds in managing risk in the international oil and gas sector and offers a note of caution.*

Hedge funds are rediscovering risk in the oil and gas industry. For the past two and half decades whenever two or more oil industry professionals gathered together it did not take long for the standard complaint to surface: 'The oil industry is no longer what it was, it's now run by lawyers and accountants. They don't understand oil, they don't understand risk, they don't understand anything!' Now the oil industry, and indeed the entire energy sector, is on the brink of another culture shock, this time administered by people who still may not understand much about oil, but most certainly know a lot about risk – the hedge funds. There are over 330 specifically energy-related hedge funds out of a total of some 8,000 hedge funds worldwide. These administer assets of some \$300bn compared with a hedge fund total of \$1tn.

Dubbed variously as the guerrillas of the investment world, the saviours of pension funds and the financial markets' very own philosopher's stone, these funds have seen their returns shrink from between 20% and 30% in 1999 to just 3% in 2004 and about 1% over the first quarter of 2005, with some funds losing about 4.3% in March 2005 alone. Facing difficult times in their traditional investments such as currencies and fixed income, the hedge funds are targeting the energy sector with gusto. They are buying into small, new upstream companies, distressed power sector assets, debt, energy trading, emissions trading of all varieties from sulphur dioxide to greenhouse gases, and even freight derivatives.

Many of the funds are empowered with some of the most sophisticated modelling software on the IT market, but their managers often have little idea of, or real direct experience in, the energy industries, observes Peter Fusaro, CEO of New York City consultancy Global Change Associates. The investment of hedge funds in fictitious or disputed upstream assets has become a common story in stock markets on either side of the Atlantic.

Price volatility

Legislators and regulators worldwide have attributed most of the volatility in oil and commodity prices over the past year to these hedge funds. However, in April this year the International Monetary Fund (IMF) said that an increase in oil trading by hedge funds and investment banks in recent years has not contributed to the volatility of oil prices. Much of the capital from hedge funds and institutional investors is invested in 'relatively passive index funds' that track spot market and futures market oil prices, the IMF said. In March this year the New York Mercantile Exchange (Nymex) issued a report concluding that hedge funds represented a small portion of traded volume from January through August 2004, and did not add to the volatility of oil prices.

For Thomas Lord, the President of Colorado-based consultant Volatility Managers, the Nymex analysis is flawed because it did not include data from the final quarter of 2004 when hedge funds took a large slice of the US gas market and contributed to significant price volatility. In one study, Lord analysed US gas price fluctuations on a weekly basis over the last 13 years and concluded that the choppiest period was from the week of 1 September 2004 to end-December 2004.

A contributory factor has been that hedge funds tended to come into the market with large trades on the exchanges, effectively blocking out the smaller operators. The overall lack of transparency in hedge funds is affecting price transparency, as well as forcing many traders away from the exchanges. 'The structures for controlling market power in the commodity markets are designed for those controlling the most,' Lord explains. With hedge funds accounting for 30% to 50% of exchange trades, what does it matter to the exchanges if one small trader is driven away? he asks.

High-risk vehicles

A hedge fund is a pooled investment vehicle in high risk and notionally high return targets, which is administered privately by professional managers and is not widely available to the retail market. The funds aim to make a return on market volatility, no matter which way the market moves. Investors have been usually institutions and high net worth individuals. But fund access has now opened to investors with over \$1.5mn in assets and who can invest a minimum of approximately \$50,000 in one stake. Some funds have even halved these limits.

Property price inflation, as well as US investors seeking to escape the plunging dollar, has meant that investors now include an increasing number of average middle class professionals, rather than the high stakes billionaire gamblers of the past. There have been moves within the European Union to broaden even further the retail side of hedge fund investments, permitting stakes as low as a few hundred euros, as is currently available in Germany. Some hedge fund managers oppose this, arguing that such individuals are in no position to understand the risks they take on.

But Fusaro has noted that the fund managers are no better enlightened than some of their investors when it comes to the energy sector. Energy trading is the most volatile and complex of the commodity markets, with prices driven by supply/demand fundamentals, weather, geopolitics, regulation etc. The hedge funds' short-term perspective is unsuited to the upstream sector, where the conventional policy of moving money in and out quickly could ruin many start-up companies. Dedicated energy hedge funds are now beginning to invest in 'funds of funds', a company which invests in other hedge funds rather than sections – this, apparently, reduces individual manager risk.

LTCM collapse

But for the managers the real incentive is not just the funds' return but also its fees. These are known as performance fees and are typically 25% of any return. Long Term Capital Management (LTCM) – the 'Rolls Royce' of hedge funds which collapsed in the 1990s and which had two Nobel prize winners among its expert advisers – charged a 2% annual fee (double the then average but equivalent to today's average rate), 25% of any profits and required a minimum investment of \$10mn. The fund built up accumulated assets of \$125bn on a base of \$4bn over four years.

The Russian and Asian financial crises were the trigger for the fund's collapse.

It lost 44% of its value in August 1998 alone. It was eventually baled out in September of the same year in a $3.625bn deal between the US Federal Reserve and 14 investment banks.

The hedge funds recovered from the LTCM crash and became more popular than ever, leaving regulators and legislators even more worried. Some are taking action. In the US under new Securities and Exchange Commission (SEC) rules adopted after Thanksgiving 2004, hedge fund managers have until February 2006 to register as investment advisers if they manage more than $25mn and have 15 or more clients. They will also have to outline investment strategies, allocation of trades and the holdings of fund managers.

However, despite these risks and the lower returns, the 'wall of money' into the hedge funds continues, mostly due to the lack of better alternatives for returns. The energy funds are diversifying their holdings into broad resource funds comprising energy, basic materials and other commodities. These can arbitrage the spread in prices between producing and consuming regions worldwide. Some funds are blurring the distinctions across the entire financial sector. A hedge fund can act as a banker to small companies in debt/equity deals which large, better-capitalised banks shun, while others are piling into the reinsurance and catastrophe bond market.

The conventional hedge fund investment targets in the currency markets are changing. The Polish zloty, currencies of other new EU members, and South Korean won are becoming overvalued because of hedge fund investment. So now, African, Turkish and various Arab currencies have become preferred targets.

Market worries

Some more circumspect fund managers are predicting a serious disaster within two to five years' time as this flood of money is making the risks worse for investors. 'Hedge funds, with their enormous supply of capital and ability to move quickly, could have a profound impact on the financing, or not, of companies of different credit quality,' says Edward Altman, Professor of Finance at the Stern School of Business, New York University. 'In the recovery of 2003/2004, marginal firms were refinanced quite easily such that many of their securities went from a distressed state to par value within a year or so. The reverse could happen if funds were pulled out quickly. In general, I expect the credit markets to be more volatile due to hedge fund activities,' he adds.

It has become as common to hear of funds closing to new investors as it is to hear of new ones opening. According to one fund manager, this only makes matters worse as aspiring investors will ask around the market until someone accepts their money. In this kind of scramble, managers who would normally struggle to raise money can have as much as they want and quality suffers. This has created a kind of vicious circle, he says. While there are inflows, managers are buying more of a position they already hold, raising prices and inflating their apparent returns. This is, of course, temporary, he notes. When there are outflows the prices can fall very far, very fast.

Risk management is possible, this fund manager says, but hedge funds have little incentive to do it well. If a fund makes a 20% return it pockets 4% through its performance fee. If the fund is offered a gamble, where it has a 20% chance to make 80% and a 20% chance to lose 100%, it has an incentive to accept. The fund is likely to win several performance fees before it loses all of its clients' money and is kicked out of the market. Investors may be able to check for this kind of behaviour, but they need to know what to look for and a fund manager has to agree to hand over some information. Most of them won't.

The fund manager interviewed by *Petroleum Review* thinks that when all of these problems are out together there is the potential for a systemic event much bigger than the LTCM collapse in 1998. This is because it will affect a significant fraction of the hedge fund industry. The next big scandal will not be one fund, he says, but a group that has collectively come to dominate one asset class. There will be some kind of a trigger, leading to forced selling, and a spiral of falling prices and further sales.

Deepening markets

But this not a common view within the hedge fund industry, especially when applied to the energy and commodity markets. More bullish managers counter that these are deep markets that will accommodate more new investors. Such markets are growing as governments seek to develop their own capital markets and launch exchanges. Iran, for example, is preparing to launch its own petroleum exchange. The government is hoping the exchange will develop into one with most Opec countries trading on it.

The various markets will broaden and deepen as emission trading grows. Aside from the European Union's greenhouse gas trading scheme, lobbying in the US by a variety of advocates, including the energy sector, could result in some form of mandatory cap and trade scheme for greenhouse gases (GHG) being introduced by the next Washington administration after 2008. In February 2002, President Bush re-introduced a dormant scheme for voluntary GHG emissions caps and credits in which companies could earn theoretical credits for any abatement measures they undertook. The power sector, which virtually bankrupted itself in the power trading scandals of the 1990s, has become a major part of the new scheme. At the moment these credits are worthless. But should mandatory cap and trade scheme be introduced in the US, the holders stand to make huge speculative gains.

Peter Fusaro expects this to be a crucial year in such green trading markets in the US, and he forecasts that the US will take the lead worldwide. It could be especially attractive to hedge funds, who may find that the power trading market itself is less profitable, where credit risk is still a major issue in an industry which has yet to recover from the 1990s disasters.

However, the mere presence of hedge funds with their collective market power remains daunting for smaller investors. 'If you go into the jungle with an elephant,' observers Thomas Lord, 'it doesn't matter who stumbles first. You get hurt.'

Liberalising Europe's energy market

Earlier this year (3 February 2005), APX Group launched two new gas exchanges in Belgium and the Netherlands, marking what it claimed was 'a new step in the liberalisation of the European energy market'. The exchanges – APX Gas NL and APX Gas Zeebrugge (ZEE) – have been developed to create transparency in the market and provide price indices that can be used as market benchmarks, writes Kim Jackson.

APX Gas NL is the new Dutch gas exchange, which enables parties to trade on the TTF (Title Transfer Facility), the virtual trading hub of Dutch gas transmission operator GTS (Gas Transport Services). The TTF is rapidly maturing into an important trading point for gas trading and, on 20 January 2005, the Dutch Minister of Economic Affairs appointed APX as gas exchange operator in the Netherlands.

APX Gas ZEE is a limited liability company owned by APX and Huberator, the Zeebrugge hub operator and a subsidiary of the Belgian gas transmission system operator Fluxys. The new exchange provides an integrated screen-based trading platform as well as clearing, while Huberator facilitates the interfaces between the platform and the Huberator system for physical deliveries at the Zeebrugge hub. In the longer term, this should trigger new opportunities to further develop Fluxys' gas transmission core business. APX will develop new services in close collaboration with the trading community.

At the Zeebrugge hub, there is a slow move from OTC (over-the-counter) trading towards cleared exchange transactions, while, in the market, there is still a perception of a lack of firmness. APX and Huberator have now successfully tackled this issue.

The two new exchanges are integrated with the established UK gas exchange – APX Gas UK (previously known as EnMO, when owned by National Grid Transco and Altra prior to July 2003) – which enables online transactions to be fully cleared and conducted anonymously. Together, the integrated system of exchanges offer day-ahead market products, including individual days, balance of week, working days next week and weekend strip, all of which can be viewed via one integrated trading screen.

The first transaction on the TTF was matched between EdF (Electricité de France) Trading and Essent, whereas on the Zeebrugge Hub, EdF Trading and Electrabel concluded their first trade.

Since the launch of the day-ahead markets on APX Gas NL and APX Gas ZEE on 3 February 2005, a total of 76,320 MWh have been traded on the day-ahead market of APX Gas NL and 1.025 mn therms (some 30,040 MWh) on the day-ahead market of APX Gas ZEE (up to 12 May 2005). In addition, since the launch of the day-ahead markets, ATEL, D-Gas Gaselys, Merrill Lynch and EGL have joined the gas exchanges, bringing the total number of participants to 11 (the initial participants being Delta, EdF, Electrabel, Eneco, E.On Benelux, Essent and NUON).

Rising and record volumes

APX Group recent announced rising April 2005 volumes for its gas and power exchanges. Its Amsterdam-based APX exchange traded volumes of 1,155 GWh in April 2005, while APX Gas UK's on-the-day commodity market (OCM) had 4,675 trades with volumes totalling 10,672 GWh (364mn therms). Volumes on UKPX's spot and prompt power exchange totalled 733 GWh.

UKPX's April 2005 volumes were a substantial increase from April 2004, where volumes totalled 448 GWh, representing a 63% increase. APX Gas UK's OCM market saw April volumes increase by 36%, with April 2004 volumes totalling 7,798 GWh (266mn therms). The Dutch power market on APX was steady, as April 2004 volumes totalled 1,138 GWh. In March 2005, APX welcomed Bergen Energi Nederland, a broker for end-users, as a new (39th) participant for the Dutch day-ahead market.

The first quarter volumes on the OCM reached 993.5mn therms (29.117 GWh), up by 25% on the previous year. The UKPX exchange (established in 2000 as the UK's first independent power exchange) experienced a 42% increase in its March 2005 volumes for its spot and prompt markets, compared with 521GWh traded in March 2004. First quarter volumes of 2,149 GWh were up by 38% on 1Q2004 at 1,546 GWh.

Commenting on the Group's performance, Les Male, Commercial Director, APX Group said: 'We have seen a strong performance for APX Group this quarter which we attribute in part to increased membership across the exchanges as well as the heightened importance of the prompt and spot contracts in the energy trading products suite.'

Recent developments

More recently, in mid-April APX launched within-day block markets on the APX Gas NL and APX Gas ZEE exchanges. Trading at these within-in day markets is possible 24 hours a day, seven days a week, via an integrated trading system.

Commenting on this latest launch, Pieter Verberne, Chief Operating Officer, APX Group said: 'The launch of the within-day market of APX Gas NL and APX Gas ZEE marks the completion of the launch of the continental gas exchanges, building upon our position as a leading energy exchange operator in north-west Europe. Trading on these new markets will generate new within-day indices that are robust and auditable. The publication of price indices and volume data of our new gas exchanges will be posted on our website at **www.apxgas.com**'

Looking ahead

Looking to the future, Pieter Verberne said: 'APX is satisfied with the first quarter results for all the APX Group exchanges and expects further growth in participants and volumes. The financial results even exceeded our expectations.'

'We are developing new innovative solutions with our partners to provide the market with solutions to facilitate energy trading, for example market coupling and third-party service provision to other platforms such as New Values (carbon dioxide certificates).'

More work required for energy market liberalisation

Claude Mandil, Executive Director of the International Energy Agency (IEA), spoke recently of Turkey's progress in liberalising its energy market. While the country has made impressive strides, the Turkish authorities still have a lot of work ahead of them if they are to obtain real benefits from the process.

'Turkey has made impressive progress in addressing energy security, economic efficiency and environmental protection since 2001,' said Mandil, speaking in Ankara at the launch of the IEA report *Energy Policies of IEA Countries – Turkey 2005 Review*. 'It has introduced new laws to liberalise energy markets and established an independent regulator. The international climate change convention has been ratified. Oil and gas infrastructure have been upgraded, strengthening Turkey's security of supply and that of the entire European continent.'

'In addition, the government has recently renewed its pursuit of the nuclear option, which could further enhance the country's energy security. Building on this success, Turkey must now focus on obtaining real benefits from energy market liberalisation and improving energy efficiency.'

Great strides

The new report indicates that Turkey has made great strides towards market liberalisation and privatisation since its adoption of the 2001 Electricity and Natural Gas Market Laws – a major milestone. The country has established an independent regulator, EMRA, and given it considerable powers. However, there is reason for concern as the Turkish government plans to keep large parts of the country's hydropower generation facilities in its hands. Turkey should avoid giving state enterprises a special role in competitive areas of the market, as it may result in barriers to entry for new market participants and investors, comments the IEA.

Despite the good legislative and regulatory framework, not much competition has developed in the electricity market. It is difficult for new entrants to compete with the state-owned incumbents and only 29% of the market is free to choose suppliers. The 'Electricity Strategy' of 2004 contains key elements for tackling these issues and should be followed. The share of the liberalised market could be increased sooner than planned and the transmission system operator (TSO) should be independent from government control, says the report.

Meanwhile, in natural gas, 80% of the market is free to choose suppliers. Nevertheless, competition has failed to develop because of the *de facto* monopoly of the state-owned company BOTAS. The Turkish government should lift contract barriers for other parties. Regarding transmission, BOTAS has been nominated as the national TSO. However, there are open questions about its independence. Legal unbundling should be considered.

With respect to EMRA, there is some concern that it has over-regulated certain markets, particularly the oil market, and should strive to take a more light-handed approach.

Cross-subsidies

The study also notes that there have been cross-subsidies in electricity and gas prices, both between different consumer groups, notably from industrial consumers to residential consumers, and between different geographical areas. The IEA commends the government for its plan to base energy prices on costs. Cost-reflective prices are a prerequisite for ensuring private investment and efficient use of energy.

Turkish hard coal production is not competitive. It receives high subsidies for social, regional and employment reasons. The IEA does not consider these subsidies justified. Turkey should reduce them, set a clear deadline for their elimination and use other means to address social and regional challenges.

Energy policy

Turkey's energy policy approach has been highly supply-oriented; energy efficiency has been a lower priority. Turkey's energy use per unit of GDP is rising – in contrast to the trend in most other IEA countries – and is now higher than the IEA average. The draft 'Energy Efficiency Law' is a good first step to realise an energy savings potential of 25% to 30%, states the report. However, to reach this goal, stronger policies are necessary, particularly in the transport sector.

Turkey's ratification of the international climate change convention should be followed by a completed climate change strategy, says the IEA. The government should consider defining emissions targets. Despite significant progress in reducing air pollution, work remains to be done to comply with existing standards by all market operators. While investments have been made to increase security in the congested tanker traffic through the Turkish Straits, continued efforts are necessary.

In the past, Turkey has had difficulties meeting the IEA stockholding obligations, which require member countries to keep 90 days of oil net imports for emergency situations. The IEA welcomes the fact that, since 1 January 2004, Turkey has continually met its obligation. However, it suggests that the Turkish government should ensure future compliance at all times by developing a new stockholding capacity and clearly defining any stockholding obligations of market participants.

High oil price – the impact on UKCS business

9 June 2005

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Photo: Renato Vicentini/Petrobras

Production ship *Seillean* (dynamically positioned floating, production, storage and offloading vessel; DP FPSO), operating on Jubarte field, Campos Basin

Heavyweight challenges

Patrick Knight *reports on how Petrobras is tackling the numerous challenges involved in getting low API crude out from reserves under very deep water and those associated with processing heavy oil on platforms.*

For several years now, Petrobras has been one of the world's leading producers of oil from large reserves located under very deep waters. About 80% of the 1.5mn b/d currently being produced by the company comes from fields in the Campos Basin, several of them under water depths in excess of 1,000 metres, with some of the newer finds under much deeper water than that.

In the third stage of an ongoing programme of research, Petrobras is developing the technology that will be needed to extract crude from reserves lying under water up to 3,000 metres deep and getting it to processing platforms. (Most of the problems involved in getting oil from fields under water between 1,000 and 2,000 metres deep have already been resolved.) However, if getting crude from beneath very deep waters was not challenging enough, an increasing proportion of the often large finds which have been made by Petrobras in the past few years, have been of oil with an API of less than 20° – some as low as 10° to 14° – and of very high viscosity as well.

Wagner Trindade is the co-ordinator of Petrobras' 'Propes' programme, which is tackling the large number of challenges involved in getting very heavy oil from deep water reserves. He says that 15bn barrels of very heavy crude has been located in place under deep waters, and more than 2bn barrels of this has been proven.

Challenging conditions

Of course, extracting and processing heavy oil is not new to the oil industry. Large amounts of crude with an API of less than 20° have been found in Canada, Russia and Venezuela, and China probably has large reserves of such oil as well. However, it is one thing to extract crudes that are usually impregnated with sand from fields on land or under shallow waters. In these conditions, the oil can be processed at facilities onshore. The resulting large quantities of sand still containing some oil can be used for road building or similar purposes without affecting the environment or polluting it in any way.

Getting heavy oil out from reserves which are not only under very deep water, but usually are located at least 150 km from the shore as well, is much more challenging. The crude has to be separated from the sand before being taken ashore, and the water used to maintain the flow rate must be cleaned before being returned to the sea.

Petrobras has some experience with recovering heavy oil from fields on land, as well as from part of the Pampa

Photo: Cris Isidoro/Petrobras

Subsea buoy being tested at Petrobras laboratory of oceanic technology, Rio de Janeiro

field, which is located in shallow water close to the shore in the Campos Basin. Some heavy oil is also now being recovered from the Marlim Basin.

As in other places in the world, if the reserves are close enough to the surface, steam can be pumped down wells and crude with an API of as low as 10° to 13° can extracted by this means. Some of the crude in Pampa has an API of 13°; this is being blended on the field production platform with lighter oil found in an adjacent deposit.

The way forward was shown a few years ago at the Fazenda Alegre field, onshore in Espirito Santo state. Heavy oil has been produced there for many years, although output has been declining recently. A horizontal well was drilled and the resulting flow was ten times as much as that from the previous vertical wells. The relatively low rate of flow achieved from vertical wells would not be appropriate for an offshore field.

For heavy oil to be produced at a competitive cost, says Trindade, a production platform has to be able to process about 200,000 b/d, ideally from only about 10 or 12 highly productive wells. The oil is separated from the sand in the well itself, by the use of very long horizontal wells of up to 1,500 metres – although wells of up to 2,000 metres are planned. Pipes of 7-inches diameter are surrounded by metal screens packed with gravel.

As well as having a low API, the viscosity of the oil found in fields such as Jubarte, Marlim, and Roncador is also very high.

According to Trindade, tests lasting six months were carried out at the Jubarte field, where the oil averages 17° API. These demonstrated that the gravel pack method works well, and flows of up to 20,000 b/d were achieved from test wells more than 1,000 metres long. Occasional blockages, as well as the entry of an excessive amount of water and very fine sand occurred at isolated points along the line. However, such incidents were not serious enough to compromise the planned lifetime of each well, which is for the period a concession lasts in Brazil – 20 years.

Various types of gravel packs developed by companies such as Halliburton and Weatherford are now being tested, including some where the mesh of screens can be adjusted by mechanical means to cope with varying conditions. So far, it has not been possible to push this type of screen through the friable sandstone for more than about 600 metres, comments Trindade. This is not long enough to result in the required rate of flow to be achieved.

In most wells, gas can be injected to help push the oil along the substantial distance from the reservoir to processing and production platforms. However, this method is not suitable where very heavy oils are concerned, explains Trindade. Where heavy oil is concerned, the gas tends to remain separate from the crude, not blending sufficiently to lift it, although the method may still be used as a stand-by. Light oil is pumped into some wells in Venezuela, but this solution would be too high cost for use on offshore Brazilian fields.

Best alternative

The best alternative seems to be very large capacity electric pumps, powered by generators located on the platforms and linked to them by umbilical power lines. For a well producing heavy oil to be economic, says Trindade, a minimum flow of at least 10,000 b/d has to be achieved, one of 20,000 b/d is considered ideal. The largest pumps now widely available are of about 900 HP (horse power), although some of up to 1,200 HP have been developed, making them powerful enough to move about 2,000 b/d.

To achieve the desired flow of between 10,000 to 20,000 b/d, several pumps would have to be fitted to each well in series, which raises the question of exactly where they should be located. Placing pumps where the pipe emerges from under the ocean floor, adjacent to Christmas trees, would allow maintenance or repair work to be carried out relatively easily. A defective pump could be lifted to the surface and on to a service vessel at relatively low cost. However, such a pump would only be at the half-way point between the end of the well and the platform, and so would not be able to operate at maximum efficiency.

Locating the pump inside the well itself would increase efficiency. But should such a pump cease to work, or have to be replaced at the end of its life, very large equipment such as a drilling platform would have to be moved to station to do the job. This would be costly and the operation would probably take considerable time.

The pumps currently available, says Trindade, usually have a trouble-free life of two years. But if one is to be inside the well, a life of at least double that would be needed.

The more powerful the pump, the more strain it is under. So, developing pumps with the necessary power associated with a very long life before the first large-scale definitive system involving pumping large quantities of very heavy oil to platforms ordered last year is due to start operating presents considerable challenges.

Production problems

It is anticipated that, as normally occurs in E&P operations, water will be injected into reserves to maintain the rate of flow. However, because of the characteristics of the heavy crude, it is anticipated that it will only be possible to extract about 30% of the total amount present in a reserve, rather than the 40% recovery normal for lighter crudes. Mixing water with very heavy crudes results in an emulsion being created, which tends to be churned up as the mix passes through pumps. This can cause serious problems, both in getting the mix to the platform and also for processing, where the water has to be separated from the oil.

Chemicals will probably have to be used to damp down the formation of emulsions, and various types are being developed and tested by different suppliers. Whatever the characteristics of the oil and water blend which reaches the production platforms, very large amounts of liquid will have to be processed on board each day.

For a production platform to be eco-

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Petrobras prospects

Production ship (FPSO) *P48* on Caratinga field, Campos Basin

Photo: Geraldo Falcão/Petrobras

The good news is that Brazil is nearing self-sufficiency in oil. However, there are worries about the longer-term impact of measures taken by the populist, nationalist government, writes Patrick Knight.

With the prospect of about 200,000 b/d of crude oil production from offshore fields operated by Petrobras being added to output this year, Brazil should be very close to self-sufficiency by the end of 2005. Delays to the completion of three large platforms which have now taken up station at fields in the Campos Basin, coupled with declining production at several other ageing fields at Campos and elsewhere, meant that an average of 50,000 b/d less was produced last year than in 2003, a fall of 3%. The reduction occurred during a year when, after remaining static for three years, demand increased by 3.5% to average 1.76mn b/d in 2004.

As a result, Petrobras had to import 173mn barrels of crude last year, 45mn barrels more than in 2003. The amount of refined product imported in 2004, 70mn barrels, was slightly less than had been needed in 2003. The imported crude cost an average of $39.96/b last year, compared with $30.57/b in 2003. The imported products – mainly diesel, naphtha and LPG – cost about $10 more per barrel last year than they had in 2003.

On the export side, the price of the 84mn barrels of heavy crude exported by Brazil in 2004 averaged $30/b, only $6/b more than in 2003, as the gap between light and heavy crudes widened. The price fetched by the fuel oil and poor quality gasoline Brazil exported rose by only $3/b on the other hand, to average $32/b. The result was that Brazil's oil account ended up in deficit to the tune of $4.75bn last year, considerably more than twice as much as it had been in 2003.

Brazil's economy is expected to repeat last year's growth of 3.5% in 2005, but the sharp increase in production should allow close to 30mn more barrels of oil to be exported this year than last. Some 27mn barrels less should be imported this year than in 2004. While up to an additional 20mn barrels of products should be exported, and only 5mn barrels more products imported.

The independent Brazilian Centre for Infrastructure (CBIE) calculates that the gap between what crude and product imports cost and what exports earn, should narrow to about $2.5bn this year, $2.2bn less than last year's record. To what degree Petrobras' financial results will benefit from the improvement to the oil trade balance remains to be seen.

Impact of product prices

The left-orientated Workers Party led government has reversed the market-orientated policies introduced by the previous government in the mid 1990s, when Petrobras' 50 years' monopoly of E&P, transport and refining was ended. Keeping inflation under control has been given top priority, with the result that the prices at which most refined products are sold in Brazil have not been increased by as much as the world price of crude has risen.

Diesel fuel, which forms almost half of all the refined product sold in Brazil – where road transport dominates – ended the year priced 12% below the world average. The price of LPG, which is widely used for cooking purposes, has not been increased for three years.

The CBIE calculates that Petrobras' profit for 2004, some $3.3bn, would have been 22% greater had products been priced at world levels. Adriano Pires of the CBIE says that in contrast to what happened to most of the world's oil companies, many of which increased profits by 50% or more last year compared with 2003, Petrobras' profit in 2004 was only 6% more than in 2003. The company tends to be more profitable when world oil prices are low than when they are high, as subsidies make a smaller impact then.

Profits and production apart, Petrobras had an eventful year in 2004. More than 1mn barrels were added to its proven reserves, taking them to just over 13bn barrels. With several very large fields still in the process of being evaluated, Petrobras anticipates almost 10bn barrels being added to reserves between now and 2010. It is expected that about 3bn barrels will be consumed during that time.

Looking ahead to 2010, when it is anticipated that about 2.4mn b/d will be being produced, Petrobras is to commission three very large platforms, which between them will be able to process just over 400,000 b/d. Most of the extra oil will be very heavy crude coming from the Jubarte, Roncador and Marlim Sul fields (see p20).

Processing capacity is in the process of being raised by about 200,000 b/d at the 11 refineries operated by Petrobras in Brazil. Two new 150,000 b/d facilities are expected to have been built by 2010, both planned to process exclusively very heavy oil. One is to make the normal range of products, the other only petrochemicals. These will enable Brazil to refine more than 2mn b/d of oil.

With production expected to rise considerably faster than consumption, Petrobras anticipates being in a position to export about 550,000 b/d of heavy crude by 2010. It will probably still be necessary to import about 170,000 b/d of light crude, however, despite the fact that it is hoped that by next year the first of what will eventually be about 250,000 b/d of light oil found recently in the Espirito Santo Basin, will be coming ashore. The increase in the amount of light crude being produced will ease the challenges faced by refineries originally built in the 1960s and designed to process crude of 30° API or more from the Middle East. Facilities which will increase the amount of light and medium fractions produced, and reduce the amount of fuel oil and bitumen, are being gradually installed at most refineries.

Gas production

With first gas from the 14tn cf Mexilhao field in the Santos Basin expected by late 2008 or early 2009, Petrobras anticipates gas consumption rising to about 100mn cm/d by then. This includes the 30mn cm/d consumed at its own refineries.

Demand for natural gas has been rising by about 14% annually in the past few years. The fastest growth has involved the use of the fuel for powering motor vehicles, now responsible for about 10% of the total consumed.

Whatever is done at refineries to increase the amount of light and medium fractions they make, large amounts of fuel oil will still be produced. With demand for the fuel slowing worldwide, the price of fuel oil can be expected to continue to slip. This could result in the product continuing to be competitive for much of industry in Brazil, thus limiting the expansion of natural gas sales.

During 2004, Petrobras acquired full control of several gas-fired power stations. This allowed the company to terminate prejudicial contracts agreed with their private owners four years ago, when electricity rationing was in force and shortages seemed likely to persist. These contracts obliged Petrobras to supply the power stations with a fixed amount of gas or pay a penalty, and to pay for a fixed amount of electricity whether the plants were operating or not. The ownership change has resulted in losses from these operations falling sharply, and Petrobras plans to acquire more power stations in the near future.

E&P stir

Brazil's Energy Minister, Ms Dilma Rousseff, who sits on the Petrobras Board, caused a stir last year by suggesting that it might not be necessary for an auction of concessions to be held this year. The auction would have been the seventh in a series started following the establishment of the National Petroleum Regulatory Agency, the ANP, in 1998.

However, following a series of protests, an auction will in fact be held in October. But it seems likely that, as occured in 2004, when Petrobras acquired 107 of the 113 blocks on offer, the company will face little competition again this year.

If it were not for the fact that Petrobras itself needs to acquire new concessions so as to maintain its own E&P operations at full steam, the series of auctions might have been terminated, or at least interrupted – despite concern and protests that this might have a very negative impact on the 30 international companies now operating in Brazil.

Rousseff says Brazil's reserves should ideally be equivalent to about 18 years' consumption, which is less than the current 23 years or so. She opposes Brazil becoming a net exporter of oil or gas.

The number of international companies interested in Brazil has now started to shrink. Most of the world's major oil companies participated with some enthusiasm in the first few rounds of risk contracts, the majority joining consortia headed by Petrobras, which was the operator on most blocks. A few of the most intrepid decided to go it alone after hesitating in the first few rounds, considering that the methods they had used with success elsewhere might prove appropriate in Brazil as well. But, although Brazil's reserves have been creeping up in the past few years, most of the oil found, mainly by Petrobras has been located under very deep water. Its API has been less than 20°, in some cases considerably less.

Political matters

Although the PT-led government is not of quite such a nationalist hue as that of Hugo Chavez in neighbouring Venezuela (see p24) nor of Nestor Kirchner in Argentina, and its line is not so populist as that now being forced on the Bolivian government, it is certainly inclined to the strengthening of state-owned companies wherever possible and has often made life difficult for the private companies.

The government has not disguised its suspicion of the independent regulatory agencies such as the ANP set up by the previous government. Whenever a vacancy has occurred on the board of one of these bodies, independent officials have been replaced by political appointees. The new nominees have included men who previously strongly opposed the curtailment of Petrobras' monopoly.

The already fairly severe regulations regarding such things as the temporary import of equipment have been further tightened. No effort has been made to clarify doubts about procedures and changes to tax liabilities that have occurred. No attempt has been made to define a long-awaited new law for the gas industry, which will define the role of all players. In its absence, Petrobras is filling the vacuum.

The decision by BP to cease searching for oil and gas after failing to find anything in a fairly high-risk effort in the Amazon region was salutory. BP had been in Brazil for many years and could have contributed in areas such as alternative energy, where it has considerable experience. Other companies, notably El Paso, have disposed of blocks in what appear to be extremely attractive areas. Others would like to do so, but are constrained by the fact that they have been unable to find a buyer for assets they bought at relatively high prices.

Newbuild vessels

Following the end of the Petrobras monopoly, the opening of Brazil to foreign capital, and a sharp rise in the company's profits as programmes with a high social content were curtailed, Petrobras found little difficulty in obtaining the large amounts of capital needed each year to maintain its ambitious investment programme. But after a gap of many years, when the chartered tonnage increased, Petrobras announced last year that the company would be calling for national yards to build 50 new ships. These will be needed to import and export crude, to carry product from those of the close to 100 production platforms not linked to the shore by pipelines, and carry product between terminals along the coast.

During the 1970s and 1980s Petrobras, together with other state companies, were obliged by the nationalist military led regimes of the time to order the vessels they needed in Brazilian yards. This was done despite the fact that such ships usually cost substantially more than ships built elsewhere. After a long suspension, the practice is now being resumed, even though Brazilian built vessels are expected to cost 25% more than those constructed elsewhere.

Should products continued to be subsidised, and Petrobras forced to enter international obligations it would rather not – such as joint ventures with Venezuela and building plants in Cuba – the company's financial position might continue to deteriorate. If it did, it might encounter greater difficulties in raising capital from abroad.

Tax, royalties and windmills

The rules keep changing in Venezuela – the government is veering towards a confrontation with Washington while, internally, the governing coalition is tearing itself apart. However, for the oil industry, the country represents an investment opportunity. Maria Kielmas *reports.*

On 22 April 2005, state oil company PdVSA announced that 29 oil companies out of the 37 that had been invited to bid in the Rafael Urdaneta gas exploration round had paid $250,000 each for technical data packages on the blocks concerned. 'This is a massive show of confidence,' said Eulogio del Pino, PdVSA Internal Director.

The week before this announcement Energy Minister and PdVSA President, Rafael Ramirez, announced that income taxes on existing operating contracts – upstream agreements signed between foreign investors and PdVSA in the 1990s – would increase from 34% to 50%. This came in the wake of increases in royalties from 1% to 16.67% for four large-scale projects that upgrade heavy Orinoco crude.

In addition, just a few days after PdVSA's acknowledgement of foreign oil company confidence in Venezuela, Ramírez said in an interview that the 'internationalisation' drive undertaken by the company in its upstream and downstream operations over the past 25 years would be 'reversed'. All of the contracts signed by the state oil company were a 'vulgarity', he said, and were 'detrimental to the patrimony of PdVSA, of the nation'. Observing these contradictions, Venezuelan commentators – assisted by the one million copies of Miguel Cervantes' novel *Don Quixote*, distributed freely nationwide by the government to mark the 400th anniversary of the book's publication – borrowed the great writer's famous expression for incredulity: '¡Cosas veredes, Sancho amigo!' [The world is full of incredible things, Sancho my friend.]

Divided views

Ever since Venezuela re-opened to foreign and private sector oil investors in the early 1990s, the industry has been divided between those who believed that the country provided one of the best chances for companies to increase both booked reserves and profits, and those who thought it was all a delusion. Today, foreign and private sector operators produce nearly 1mn b/d of Venezuela's total oil production of 3.4mn b/d, according to government figures – the latter figure estimated at 2.717mn b/d according to Opec, or 2.1mn b/d according to the International Energy Agency (IEA). About 1.2mn b/d of production is exported to the US market, accounting for nearly 12% of US oil imports.

The Venezuelan Energy Ministry claims that foreign companies will invest $16bn in Venezuela over the period 2005–2011. Of this total, $6bn is scheduled from a joint venture by Repsol-YPF and Chevron in heavy crude upgrading, with a further $10bn to be invested in other heavy crude projects.

Without maintenance and exploration, production from Venezuelan reservoirs declines at 21% to 25% annually. PdVSA's upstream investments have been cut severely since President Hugo Chávez assumed office on 1 February 1999. In its latest five-year plan (2005–2009) PdVSA aims to invest just $2.431bn in exploration – an amount similar to the sum it provides annually towards President Chávez' social welfare programmes. PdVSA claims that its own oil production is 2.43mn b/d and that this will increase to 3.8mn b/d by 2010.

Reversal of fortunes

During the Asian financial crisis and low oil price years of 1997–1998 PdVSA's strategy under its then President, Luis Giusti, was to capitalise on the country's low production costs, to increase oil output irrespective of Opec quotas and to capture as much of the North American market as possible from Middle East exporters. PdVSA's critics at home said that the company's vast investment programme was distorting the local economy and resulting in social welfare spending cuts.

Abroad, the expansion programme was dubbed 'piracy' by Opec and non-Opec producers alike, especially Saudi Arabia whose government oil officials indulged in an unseemly Transatlantic exchange of insults with their Venezuelan counterparts. However, business liked it and, as a result, Wall Street bankers, the local and international oil industry, and a substantial proportion of the Venezuelan business establishment hoped that Giusti would stand for President as an anti-Chávez alliance candidate.

Chávez' popularity was soaring as Venezuela's old political structures disintegrated. Now, after six years of Chávez-led governments that restored Venezuela's allegiance to Opec quotas, Saudi Arabia is preparing to expand its own oil production and capture as much as it can of what remains of Venezuela's diminishing US markets. Chávez, meanwhile, hopes that Venezuela will diversify its oil exports from the US and towards Asian markets, even though distance, logistics and the lack of refining capacity which can process Venezuelan crudes make this appear, at first, an unrealistic ambition.

Sovereignty

With most of PdVSA's revenues going towards government programmes and, according to widespread media reports, in fees and kickbacks to intermediates and third parties in various trading contracts, the government is preparing a greater sweep against the foreign investors.

This began in April last year, when President Chávez announced a campaign to restore 'sovereignty' to the oil sector – 'Plena Soberania Petrolera'. The first phase of this – 'Plan Colina' – has been to rid PdVSA of its old 'oligarchic and transnational' interests. The second phase is to increase taxes on foreign investors so that PdVSA is not disadvantaged.

As a result, Chávez announced that royalties on Orinoco heavy crude production would rise from 1% to 16.67%. However, PdVSA pays a 30% royalty for its share of Orinoco production and it seems likely that, sooner or later, foreign investors will face another royalty rise to 30%.

Diversifying markets

When Rafael Ramírez was appointed as both Energy Minister and head of PdVSA, the oil sovereignty campaign began in earnest. Ramírez' most defining characteristic is his intense anti-US feeling, as well as long family ties to former guerrilla groups. His father was an accountant who, in the 1960s, supported and financed various guerrilla movements, including those to which former PdVSA chief and now Foreign Minister, Ali Rodríguez, as well as President Chávez' brother, Adán, once belonged. In 2001, he created an energy task force that travelled throughout the US in the hope of attracting foreign oil investment to Venezuela, acquiring a reputation as being intelligent, well briefed and organised.

The new oil policy came quickly. First, there was the intention to diversify export markets and to forge broad energy agreements with both major producers and consumers. These now stretch to China, Russia, Iran, India and Brazil, and have led policymakers in Washington to fear that Venezuela is creating an anti-US oil alliance. In response, the US Congressional watchdog, the General Accounting Office (GAO), is preparing a study on all aspects of the Venezuelan oil industry. Adding to the US fears has been the ingraining of military control over the economy by the armed forces. In this matter President Chávez was influenced by Norberto Ceresole, an Argentine sociologist who, until his death in 2003, was a neofascist and Holocaust denier and who had advised other governments such as the leftist military dictatorship of Juan Velasco Alvarado of Peru, Salvador Allende in Chile and most recently, President Mohammad Khatami of Iran. But this military strategy may yet backfire on Chávez at home (see below).

The reshaping of Venezuela's crude exports is now underway with a triangulation agreement between Russia, China and Venezuela. Based on previous deals with Russia over oil exports to Cuba, the scheme seems to be that Russia will sell refined products to China on Venezuela's account while, in return, Venezuela will service Russian clients in North and South America. PdVSA sees China as a growing market for gasoline, lubricants and asphalt. The deal could have ramifications for the global lube market as it may also involve the sale of some of PdVSA's US subsidiary, Citgo's, assets in the US. US-based analyst Kline & Co suggest that Lukoil could provide the financing to upgrade Citgo's Lake Charles refinery in Louisiana to produce Group II and higher basestocks. The government has already put two of Citgo's US refineries up for sale, just as refining becomes a profitable business.

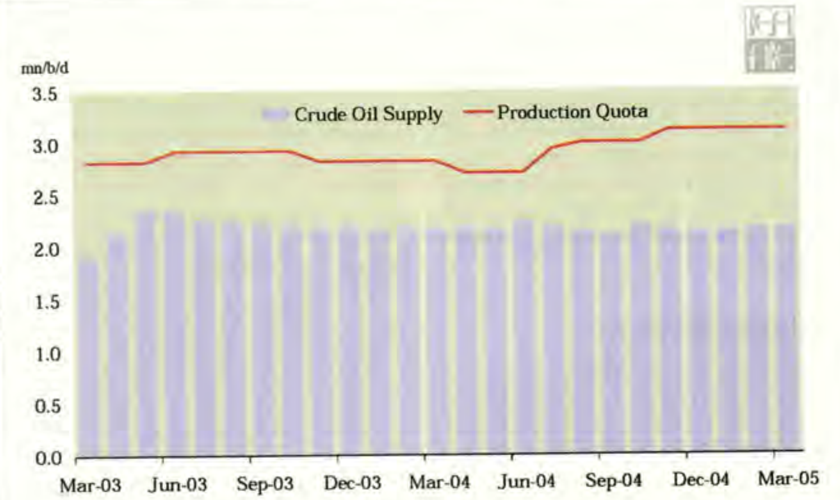


Figure 1: Venezuelan oil production versus Opec quota
Source: International Enery Agency (IEA), Oil Market Report, *12 April 2005*

Contract review

The new PdVSA Board under Ramírez announced in December last year that it would review all contracts with foreign operators. These will be changed into joint ventures with PdVSA, where the state company holds at least 51% in line with the new oil regulation. The old agreements will be phased out by December of this year. In the meantime, income taxes on the 32 operating agreements have been raised from 34% to 50%. The government's justification for this is that it lost $260mn last year as a result of the operating agreements. In addition, it alleged that the foreign operators evaded payment of $2bn in taxes. The agreements themselves stipulate that income taxes are not levied until investments have been repaid, but this has been ignored.

One the most important influences in drafting oil policy has been German-born sociologist Bernard Mommer, who was appointed as an External Director of PdVSA in December last year. A holder of Venezuelan and five other nationalities, Mommer was a close associate of Foreign Minister Ali Rodríguez when the latter was an opposition congressman in the 1990s, PdVSA chief, Energy Minister and Opec Secretary-General. The two collaborated on the drafting of the 2001 hydrocarbon legislation that has led to the step-by-step revision of the entire 1990s oil opining, or *apertura*.

Rodríguez and Mommer believe that that *apertura* and bilateral investment treaties guaranteeing investors' rights, which were negotiated in the 1990s, are a betrayal of the national interest. In their view, oil producing states should be 'landlords', while commercial operators are 'tenants' with lesser, derived and transitory rights. In contrast to international commercial practice where, say, E&P in Venezuela is an investment opportunity, Mommer and Rodríguez believe that the state should give temporary access, at the highest possible rent, royalty, income tax and capital investment obligations, to commercial operators of its natural resources. This is a direct response to the international experience of the 1980s and 1990s, when government revenues from large projects were delayed for many years after first production. The overriding principle here is ideology, not what international business regards as rational and of economic necessity.

Companies under pressure

US companies ConocoPhillips and Harvest Resources came under particular pressure in January this year when PdVSA refused to approve their investment plans. PdVSA wanted to reduce its own share of cost in such marginal field projects. The company said that operating costs in these projects were $12/b compared with the state company's own operating costs of $5/b. Operating costs of the heavy oil upgrading projects are $9/b, according to PdVSA. The new oil policy logic is that it is more profitable for the state company to substitute marginal field production with cheaper conventional production. Even if oil production from the 32 contracts were to be cut in half to about 200,000 b/d, it would still save the country $500mn annually.

Whilst such a policy may be regarded as economically irrational among business experts, the government is staying on this path. The gamble is that oil prices will remain high for many years to come. However, production setbacks and reservoir problems could mean that such an edifice will unravel sooner than expected.

Coalition divisions

The real issue today, however, is the survival or otherwise of the governing coalition. This comprises Chávez' own party, Movimiento V República (MVR), and Patria Para Todos (PPT), of which Foreign Minister Rodríguez is a leading light. The two sides have accused each other for years of embezzling oil revenues. Now, the PPT is said to be organising armed militia groups which will tackle Chávez' own street gangs, the Bolivarian Circles.

Chávez has been under pressure for some years to get rid of PPT Ministers in his Cabinet, but rumours about his allies began in earnest in late 2004 following his intemperate, and much delayed, reaction to the capture in Venezuela of Colombian terrorist Rodrigo Granda. It took more than one month – and then only following a leak of information from Bogotá – for Chávez to gather up the necessary outrage for the supposed slight again Venezuelan sovereignty. Granda was captured by Venezuelan police, who were working for a $1.5mn bounty paid by Colombia. Inevitably, Washington was implicated in the episode and raised even further the temperature of Chávez' anti-US rhetoric. Local sources believes that Chávez' assertion that the US government is about to depose him may just be a reflection of his nervousness about support on the home front.

When Ecuador's President Lucio Gutiérrez – also a former lieutenant-colonel who modelled himself on Chávez – was ousted following street demonstrations by students and the middle classes, Chávez compared this to the April 2002 attempted coup against himself. Since 2002, Chávez has acquired more popular support despite an increase in poverty, partly as a result of PdVSA-funded welfare programmes modelled on similar Cuban programmes, the misiones, and partly because of divisions within the old opposition.

However, US-Caracas tension has increased with Venezuela's purchase of 100,000 AK-103 and AK-104 assault rifles from Russia, on top of new frigates from Spain. Chávez' critics at home and abroad believe he plans to disband the national armed forces, where some top generals are known to oppose him, and create 100,000 new reservists led by his allies. According to Gustavo Coronel, a petroleum engineer and former PdVSA Director, Chávez has wasted $150bn of oil revenues in his six years in power. He remains in power because all of the country's' institutions are under his personal control, while an all-pervasive militarism has frightened the population.

Tax demands again

In January the tax authority, Seniat, announced that it would review the operations of all foreign oil companies in Venezuela, as well as all foreign non-oil companies such as McDonald's and Coca-Cola. Employees of private businesses who face tax problems have been encouraged to take over those businesses, without compensation to the owners. Land expropriation is also gathering pace in a country where the state already owns 60% of the land.

The government will still need the foreign oil companies to explore for and produce the oil and gas it cannot afford to do itself. And the companies are attracted to Venezuela's large reserves. However, it is an open question as to which side is tilting at windmills. Maybe both.

...continued from p21

nomic, it will have to be able to produce up to 200,000 b/d of heavy crude oil. So, up to 300,000 b/d of the water-oil blend that reaches the surface will have to be processed. The fact that little gas is associated with the heavy oil found in Brazil, simplifies things slightly. Water and oil from most wells are separated either by gravity, a process which takes considerable time, or by some form of heat treatment, which involves high temperatures. In both cases, the fact that such massive quantities of oil and water will have to be separated on platforms each day, means that the search is on for much more compact processing facilities than are now available.

Given the constraints of space, however, an alternative method such as treatment by centrifuge may prove to be more appropriate. The centrifuge method is used successfully in the mining industry, says Trindade. It may be possible to adapt centrifuges for use on platforms before the first very large-scale dedicated production of very heavy oil is scheduled to commence in 2009.

Trindade notes that most production platforms are built on the hulls of ships, objects designed to move easily through the water, rather than remain stable in it. Because of the difficulties in separating such large volumes of liquids, more stable conditions than are offered by the present structures would be more appropriate for platforms which are processing very heavy oil. Hulls of a more spherical shape, which can be tethered more steadily, may prove more appropriate.

Another problem to be considered is what might occur should the flow of very heavy crude from the field to the production platform be interrupted for more than a very short length of time. The 17° API crude in the Jubarte field, for example, emerges from the reservoir onto the platform at about 4°C, and loses about 1°C each 24 hours. This means that a short halt to the flow should not cause a problem, although a longer one would.

Experiments are being conducted into finding a method whereby should the flow of crude come to a halt for any reason, the electric pumps that will normally push crude to the platforms could be switched to heating pipes instead. In some cases, pipes may have to be lagged. It may prove necessary to heat the crude as it is moved from production platform to ship or marine terminal, either in Brazil, or in the countries to which some heavy crude will continue to be exported.

Oil exports and refining

Despite the fact that major investments are being made at the 11 existing refineries to allow them to process steadily increasing quantities of low API crude, a considerable amount will still have to be exported. Brazil should become self sufficient in oil at the end of 2005, or early in 2006, and about 500,000 b/d of heavy crude may be surplus to domestic requirements by 2010 (see p22).

Petrobras is also developing a project to build a brand new 150,000–200,000 b/d refinery jointly with Venezuela's PdVSA. Such a refinery will be specifically designed to handle Brazilian heavy crude and, if the economics are right, probably some from Venezuela as well.

Petrobras is also planning to build a new 150,000 b/d petrochemical plant that will use exclusively very heavy crudes. The advances which are being made with finding ways of extracting heavy crude from recently made finds will also be used to recover more of the crude in several fields that have already been producing for some time.

Sir John Collins looks to the future

Sir John Collins, *the President-Elect of the Energy Institute (EI), was recently interviewed by* Chris Skrebowski, *Editor of* Petroleum Review, *at Dixons headquarter's in London. Sir John's latest position as Chairman of the Dixons group is the most recent in his glittering business career.*

Sir John started by noting that business had not been his chosen career. He had been studying agriculture at Reading University, confidently expecting to inherit and run his father's large farm in what was then Rhodesia, now Zimbabwe. However, any plans he might have had were dramatically overturned in his final year by a letter from his father – informing him that the farm had been sold, his father was going to live in Fiji, his university fees had been paid and enclosed was £50.

Confronted with this dramatic sink or swim challenge, the young John Collins then did the 'milk round' of Shell, Unilever, ICI etc that was the standard recruitment practise of the time – he chose to be recruited by Shell. This was to be the start of a 29-year career with the company, which he modestly describes as 'exciting and diverse'.

Shell career

Given his farming background, it was unsurprising that Sir John started in agrochemicals before moving into petrochemicals and, finally, into oil. In the course of his career with Shell, he worked in the UK, Kenya, Nigeria and Colombia. When asked which country he had enjoyed working in most, he unhesitatingly picked Kenya. With a twinkle in his eye, he agreed that at least part of the reason was that he had played both rugby and cricket for East Africa, which he had hugely enjoyed and which had stood him in good stead in the company.

Sir John's career in Shell culminated in his appointment as Chairman and Chief Executive of Shell UK in 1990. As Shell was a highly decentralised set of baronies and Shell UK was the second largest subsidiary, he had, in effect, become the second biggest baron in the group. Now equipped with the power, authority and responsibility for a £6bn/y company, Sir John explained that he had initially seen his role as 'sharpening the marketing'. However, these plans and ideas were rapidly overtaken by the first Gulf War and the collapse of production at the Brent oil field, caused by lack of maintenance.

A 'brownfields' task force was then formed to tackle the production problems. This drew on expertise throughout Shell and was led by Chris Fay, who headed up Shell Expro. Sir John's summary of what was clearly a difficult and challenging time was that he had been 'set to do one job and ended up doing another'. However, he felt that the way things were tackled and the objectives achieved showed Shell at its best.

Head-hunted

Challenged as to why he left Shell in 1993, Sir John explained that he had been head-hunted to run the Vestey group, which had run into difficulties and needed to be turned around. One inducement to take on this very challenging job was a profit share for success. He also noted that it always makes good sense 'to leave while the party is still good'. The move to Vestey, at one level, took Sir John back to agriculture, with the company owning and running vast areas of land, particularly in Latin America, as well as having major shipping interests in its worldwide business.

Sir John confirms that he did turn the business around, earned his profits share and stopped, as planned, at 60.

However, any thoughts of retirement, or even a slower pace of work, were quickly dispelled when he was head-hunted to be Chairman of Dixons – to take over from the legendary Sir Stanley Kalms. In fact, Sir John did one year as Deputy Chairman before taking over as Chairman in 2002.

Questioned as to how he handled the relationship with Lord Kalms after taking over from him, Sir John explained that he took two pieces of paper and wrote down the role to be played by each of them. He says that by defining and agreeing clear lines, they established a harmonious working relationship that played to both their strengths.

Sir John then went on to explain that his role in the City, as a board member of Rothschilds, had taught him the importance of informing shareholders and keeping them onside. He says that he finds talking to analysts and shareholders exciting, particularly as investors have become more proactive. Sir John becomes quite animated when talking about relationships with shareholders, stressing the importance of clarity of purpose if you wish to be supported. Gaining support and buy-in by employees, suppliers and financial backers appears to be the hallmark of Sir John's approach, with clarity and delivery being the other factors in a highly successful equation.

Energy policies

Sir John explained that he was fascinated by energy and its importance within our societies, which was why he had been happy to accept the Chairmanship of the DTI/Defra Sustainable Energy Policy Advisory Board. Sir John commented that he had been closely involved in developing the Energy White Paper and had been on the Prime Minister's Energy Committee. The challenge had been in balancing the traditional energy policy requirements of security of supply and fuel diversity with the need to have a policy that delivered on emissions targets to ensure that threats from climate change were minimised.

One strand of the policy was increasing use of gas and, with North Sea supplies now declining, this necessarily implies increasing imports. Sir John noted that supply security can be addressed by using multiple suppliers, but this meant large-scale infrastructure investment, particularly if gas was imported as LNG. He was pleased to report good collaboration between industry and government, which meant there were already firm plans to import the required volumes via pipeline and as LNG. He went on to explain that with the dominant position of state-owned or partially state-owned companies (Saudi Aramco, Gazprom etc) government involvement with Russia and Opec necessarily involved a wide range of government departments, including the Foreign Office, in the implementation of energy policies.

Renewables debate

Turning to renewables, Sir John noted that this was one of the most debateable parts of the policy. Wind power was currently facing challenges in terms of making itself acceptable to society, particularly in terms of the aesthetics in areas of outstanding natural beauty.

The response of the wind industry had been good in terms of its preparedness to invest. However, the problems of intermittency meant that the 'jury was still out' on the scale of the stand-by capacity required and how these costs were to be borne. Social acceptability was another challenge and the target of 20% of renewable (emissions-free) power by 2020 looked highly problematic without a role for nuclear power.

Sir John's view was that once the election was over, nuclear power would be back on the agenda. He noted, however, that there were a number of challenges to be overcome. The first was the safe and effective disposal of spent fuel. He stated that he had been somewhat disappointed by the lack of innovative solutions to this problem and hoped people would be more imaginative in the future.

The second challenge was to find investors in the new capacity. This would also require imaginative solutions.

Thirdly, society had to be convinced that nuclear could be a safe and effective power provider.

Sir John explained that providing a suitable financial framework was not impossible. Offtake contracts – successfully used in the LNG industry, which also has multi-billion dollar investment requirements – are a real possibility. This, however, would require electricity trading arrangements to be reworked and recast. In terms of securing public acceptance, he felt that we, as a society, needed to be much clearer on the benefits, but accepted that extended consultations would be needed to build broadly based acceptance. Sir John also felt that we could learn from the Finnish experience, where extended consultations with all interested parties had secured acceptance for the building of their fifth nuclear power station.

In terms of overall energy supplies, Sir John felt that the UK was well served by a number of good companies in the oil, gas and electricity sectors. This enabled the UK to 'play the game on international terms', to the considerable benefit of the country. There was, he noted, a fascinating trend, particularly in the oil and gas sectors, for producing country companies to become more powerful, leading to an accompanying loss of power by the international companies. The result of this was that it was very important for the UK that the government had good relations with producing countries, in order to negotiate production contracts.

National companies such as Gazprom had much to offer in terms of security of supply for the UK. Sir John felt, however, that negotiating major long-term contracts would need to involve key government departments such as the DTI and the Foreign Office. In an important sense, the stakes are rising as fewer countries control incremental supplies. This, Sir John explained, means that energy and energy supply will remain very high profile and, in this context, the Energy Institute is set to become an important voice. The Energy Institute is in a position to facilitate debate, which will lead to recommendations for action.

Sir John felt that there was a need for fiscal encouragement to stretch out North Sea supplies but, in terms of negotiating with new suppliers the country was a potential winner as it was 'well equipped to play that game'. This would enable it to cooperate with others from a position of strength.

EI – right place, right time

Sir John explained that he felt very strongly that the Energy Institute (EI) was the right organisation at the right time. It was in tune with the real issues of today. The merger had been sensible as it had produced one real professional body for those in the energy industries.

Sir John is currently Chairman of Dixons Group and a non-Executive Director of N M Rothschild & Sons and P&O. He is Chairman of the DTI/Defra Sustainable Energy Policy Advisory Board, President-Elect of the Energy Institute and a Companion of the Chartered Management Institute.

In 1964, having graduated from Reading University with a BSc in Agriculture, he joined Shell and held various positions in Kenya, Nigeria, Colombia and the UK, culminating as Chairman and Chief Executive of Shell UK from 1990–1993.

From 1993 until the end of December 2001, he was Group Chief Executive of the Vestey Group of companies. He joined the Board of National Power as a non-Executive Director in October 1996 and was Chairman from January 1998 until October 2000 when the company demerged. He was a non-Executive Director of British Sky Broadcasting from November 1994 until November 1997, Stoll Moss Theatres from 1999 to 2000 and Chairman of Cantab Pharmaceuticals from 1996 to 1999.

From April 1991 until August 1993, Sir John acted as Chairman of the Advisory Committee on Business and the Environment and, in May 1993 was knighted for his services to government and industry.

Sir John has served as a Director for the London Symphony Orchestra and chaired a campaign to raise funds for Action on Addiction.

He has also assisted with fund raising for various other charities, including the Jubilee Sailing Trust and the Ocean Youth Trust.

He is married, with two children.

He explained that he was privileged to be President (Elect) as he had been impressed by what he had seen, and felt that the EI had a real cutting edge and a refreshing approach, which was good for a professional body.

Sir John also noted that the key to success was satisfying the membership and that the challenge was establishing what the members wanted and constantly checking that the Institute was meeting members' requirements. It was also important to be aware of, and deal with, any shortcomings. It was particularly important that the EI remained a respected voice and one that was contributing to the national debate. However, the EI should not lobby, its views should be clear, but it should not have a particular point of view. It should command respect and be seen as 'a voice that matters', said Sir John.

Asked how far the EI should go in developing an international role, Sir John's view was that one should 'see how far the carpet unrolls' – in other words, go with it, but don't push it. With existing branches in the US, South Africa and the Far East, there was a good base on which to build.

Sir John felt that the EI is, and should be, an excellent vehicle for 'networking'. Not just in terms of meeting and interacting with people, but also in terms of accessing the skills of the membership within an organisation whose pedigree would be endorsed by the government. The EI had a role to guide and support the execution of policy and to be its ambassador.

Asked if he thought the EI should be rounded out to cover all the major energy sources, Sir John agreed that over time coal and nuclear should be added. This would then mean that the EI could become the umbrella professional body for all aspects of energy supply.

Asked about his leisure activities, Sir John explained that he was not a workaholic and did not believe in working long hours, which gave him time to spend with his family and to pursue his interests in sailing (there is a large picture of his boat on his office wall) and his sporting interests – tennis, golf and horse riding. With mounting enthusiasm, he explained that he loves going to Africa, where he has conservation interests.

Without any embarrassment, Sir John explained that he enjoyed his leisure time and his life, which he said had 'been kind' to him. He felt that many business people relish pressure and end up working too hard and interfering too much. His view was that for business leaders it was 'the quality of decisions that matters' and excessive hours rarely made for good decisions. He enjoyed his success and recognised that he had a privileged position. He explained there were, of course, some bits that you don't enjoy – rationalising costs and firing people being just one example – adding rather tartly, 'anyone who enjoys firing people needs to see a doctor'.

Sir John Collins is, by anyone's standards, a charming and clear-sighted business leader who obviously enjoys nearly everything he does. His success is in no small measure the result of a clarity of purpose and a deep understanding of what motivates people. It would appear that the EI is very fortunate to have him as its next President.

World-class gas developments signal new era for Egypt

It attracted little in the way of media fanfare but, during the beginning of January 2005, the first shipment of LNG left the recently built Damietta plant on the Mediterranean coast of Egypt. The country has recently increased its estimate of proven gas reserves to 66tn cf and this shipment of a modest 5mn cf to Spain signals a new dawn for Egypt as this year will see a quantum leap in the utilisation of gas, writes Ken White *from IHS Energy Tebury and* Michel Marchat, *Area Coordinator, IHS Energy Geneva.*

The $1.4bn Damietta plant was developed by Spanish Egyptian Gas Company (Segas), a joint venture comprising Union Electrica Fenosa and Eni of Italy with an 80% stake, and two state bodies, the Egyptian General Petroleum Corporation (EGPC) and the Egyptian Natural Gas Holding Company (EGAS), holding 10% each. The facility has a production capacity of approximately 700mn cf/d and is now operated by Union Electrica Fenosa, the company signing a deal to deliver 150bn cf/y over 25 years to the Spanish LNG market.

This is the first of two major gas development projects. The other project will see first exports in May 2005, from Train 1 of the Idku plant located close to Alexandria on the Mediterranean Coast. The entire 3.6mn t/y output of Train 1 has been sold to Gaz de France under a 20-year agreement. Train 2 is scheduled to produce its first cargo in mid-2006 and all output from this unit has been sold to BG Gas Marketing (BGGM) under a 20-year agreement. For approximately the first year of LNG production, BGGM intends to supply the entire output to the Lake Charles LNG terminal in Louisiana, US. After the first year, a portion of Train 2 output will be supplied to the Brindisi LNG import terminal in Italy. There is sufficient space at the Idku site for a further four LNG trains and BG has been considering for some time commercial options for the construction of a third train, with all production likely headed to markets in the US.

Other gas initiatives are sure to follow for Eni which, through its International Egypt Oil Company (IEOC), awaits the outcome of a development plan submitted for gas fields discovered in its North Bardawil exploration block, offshore the Nile Delta. In what has proved to be a highly prospective permit, the company has declared the Fahd, Assad, Hadeer and Zaraf commercial discoveries. In addition, German company RWE Dea awaits a decision on its application for a development lease over the Idku North 2 gas discovery in the North Idku block, offshore the western Nile Delta, for which reserves of 800bn cf have been assigned. Here, the company has expressed an interest in developing an LNG project and has declared itself willing to invest $1bn on such a scheme in Egypt.

Smaller opportunities

While LNG related projects may dominate the headlines at the moment, gas development opportunities are more widespread in Egypt and do provide opportunities for the smaller players to be involved. A case in point is Canadian company Centurion Energy, which, through a company called Wasco, operates three development leases carved out of the El Manzala concession in the onshore part of the Nile Delta. The company has been ramping up production since October 2004 and was expecting to be producing around 90mn cf/d of gas by the end of 2004, en-route to achieving the full contract quantity by the end of 2005.

The gas will be produced from dedicated reserves in the El Wastani and South Manzala production leases, where an 18-well drilling programme is currently underway. Centurion has also initiated engineering and procurement work for the construction of a company-owned gas plant in the El Wastani area. The new plant will be built to accommodate all of the company's projected production in the area and is expected to be operational by the end of 2005. On 6 January 2005, Centurion announced a new record production of 21,150 boe/d at the end of 2004, comprising approximately 19,250 boe/d from its Egyptian fields.

Texas-based Merlon Petroleum is also successfully carrying out a very active appraisal and development programme in the Kafr El Sheikh Mansouriya channel trend and the Abu Madi channel system in the onshore Nile Delta. Production from El Mansoura is expected to reach 150mn cf/d by mid-2005.

Major discovery

During recent years, most of the gas discovered in Egypt was from the Nile Delta. However in 2003, the Qasr 1 discovery by Apache Oil was a major event. Made in the Khalda Offset acreage, Qasr 1 is the most significant gas discovery made in the Western Desert in the last decade. The Qasr 1 and Qasr 2 wells confirmed a 200-metre gas/condensate column with ultimate recoverable reserves now estimated to be in excess of 2tn cf of gas, with 50mn barrels of condensate.

Qasr 1 was brought onstream in

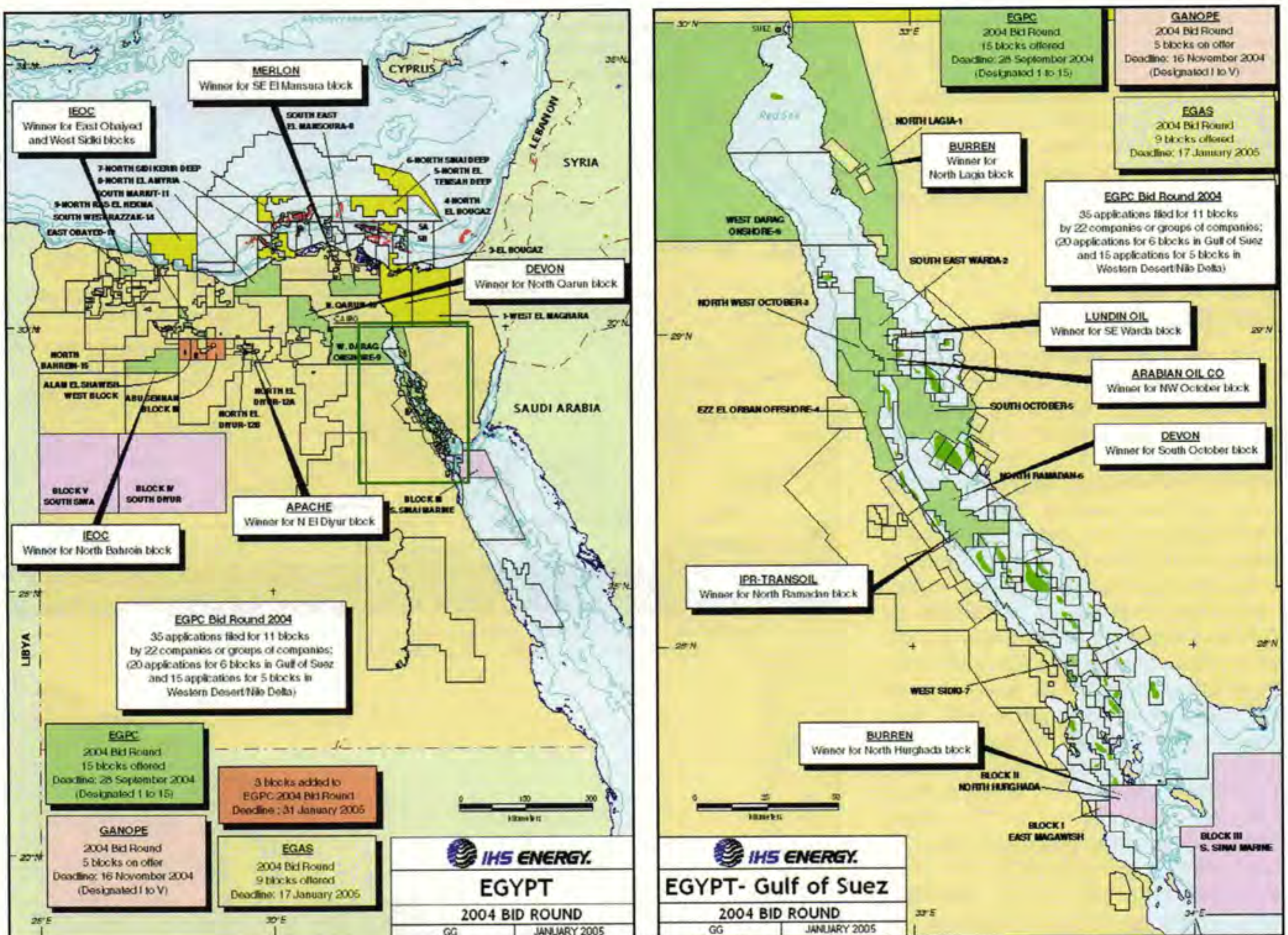


Figure 1a and b: Successful bidders in Egypt's 2004 Licensing Round

December 2003 at a rate of 10mn cf/d. As additional appraisal and development drilling continues, Apache is working on development plans to deliver significant gas volumes from Qasr in 2005. In April 2004, the company signed a gas sales agreement (GSA) with EGPC to supply 2.1tn cf of natural gas to the Egyptian market, by adding gas deliveries from the Qasr field. Total revenue to both parties under the 25-year agreement is approximately \$5.5bn, net of estimated development and infrastructure costs. As for previous years, Apache was the most active operator in Egypt in 2004, obtaining five discoveries during the year (three oil and two gas) compared with seven in 2003 (six oil and one gas/condensate). In addition, the company reached a record with 100,828 b/d of oil and 276mn cf/d of gas produced in Egypt in 2Q2004. During that period, the company's net share was 51,200 b/d of oil and 133mn cf/d of gas.

Decline downside

The downside for Egypt is that crude oil production has started to decline – the figures showing a fall from some 620,000 b/d in 2003, down to an estimated 590,000 b/d in 2004, with particular concern directed towards the maturity of the giant fields in the Gulf of Suez. As a consequence of licensing in recent years, exploration drilling for oil has significantly increased in the Gulf of Suez, where eight wells were in progress in December 2004 compared with an average of three or four per month during previous years.

It is estimated that to maintain current levels of production it is necessary for Egypt to discover at least 260mn b/y of oil. Since the turn of the Millennium, however, the quantity of oil discovered per year has been estimated at between 100mn and 150mn barrels.

More than 410 fields have been discovered in Egypt to date, almost 170 of which are currently producing. Astute planners had predicted the decline in oil production some time earlier, such that the development of the nation's gas reserves is significantly advanced in order to compensate. In 2003, Refaat Khafagi, Vice Chairman Exploration & Agreements, indicated that reserves yet-to-find were estimated at 65tn cf in the Mediterranean, between 1.5bn and 3bn boe in the Gulf of Suez, and between 2.5bn and 5bn boe in the Western Desert. In 2004, exploration drilling has been particularly successful, with a total of 29 discoveries from 81 spuds. Within this are 16 oil, 12 gas and one oil/gas discoveries, which bode well for the future. This compares with 33 discoveries (20 oil and 13 gas) during 2003. Gas production has been steadily ramped up and currently averages 3.5bn cf/d, while domestic energy consumption is rapidly increasing. By comparison, local gas consumption averaged 2.8bn cf/d in 2003, compared with about 1.3bn cf/d in 1998.

In October 2004, a new joint operating company called Norpetco was awarded the large North Bahariya development lease in the Abu El Gharadiq Basin, Western Desert. The company will produce a number of recent oil discoveries made by Sipetrol, a Chilean company of the Enap Group, in the former North Bahariya exploration block, and which may total an estimated 100mn barrels of oil in place. Two of these fields, Ferdaus and Ganna, were put onstream in

September 2004, recently followed by two other fields, Abrar and Rawda. Sipetrol has joined Apache and the Tunisian outfit Hedi Bouchamaoui as successful companies having found significant quantities of oil in the Western Desert in recent years, which partly compensate the decline in the country's oil production.

Middle East and European ambitions

Egypt also has ambitions to be a player in the regional Middle East gas market, which is being driven by growing demand in Israel, Jordan, Lebanon and Turkey, as well as in the European market. According to Egyptian sources, total proven reserves amounted to 15.3bn boe at the end of 2004, compared with 14.6bn boe at the end of 2003 and 14.2bn boe one year earlier. Proven oil reserves are estimated by official sources at around 4bn barrels of oil, and at between 2.8bn and 3.7bn by industry sources. Gas reserves were estimated at 66tn cf at end-2004, representing almost 75% of the country's total hydrocarbon reserves. In 2004, the total addition of hydrocarbon reserves amounted to 1,315mn boe. The increase of gas reserves is spectacular when compared with 37tn cf at end-1998 and 12tn cf at end-1992. Most of the gas discovered during the last decade comes from discoveries made in Tertiary channel sand systems of the offshore Nile Delta by a few players such as Apache, BG, BP, Eni and RWE Dea.

The authorities hope that these figures will change substantially as the search moves into deepwater. In this respect Shell, which describes the ultra-deepwater area as a rich hydrocarbon province, may duly oblige in 2005. The company is planning a third drilling campaign in its NE Mediterranean Sea Deepwater block C (NEMED), offshore the Nile Delta, for the second and third quarters of 2005. It is understood that the programme will include a number of appraisal wells to delineate the two recent discoveries made in the block for which little information has been revealed. Teasing the industry, the company indicated that it has tested a variety of hydrocarbon plays in the south-west of the concession and that it is embarking upon a 4-year second phase to commercialise the discoveries as rapidly as possible.

On the licensing side, eight development leases were awarded while a total of 29 production sharing agreements were approved by authorities in 2004. Licensing continues to attract a wide range of players and a good response

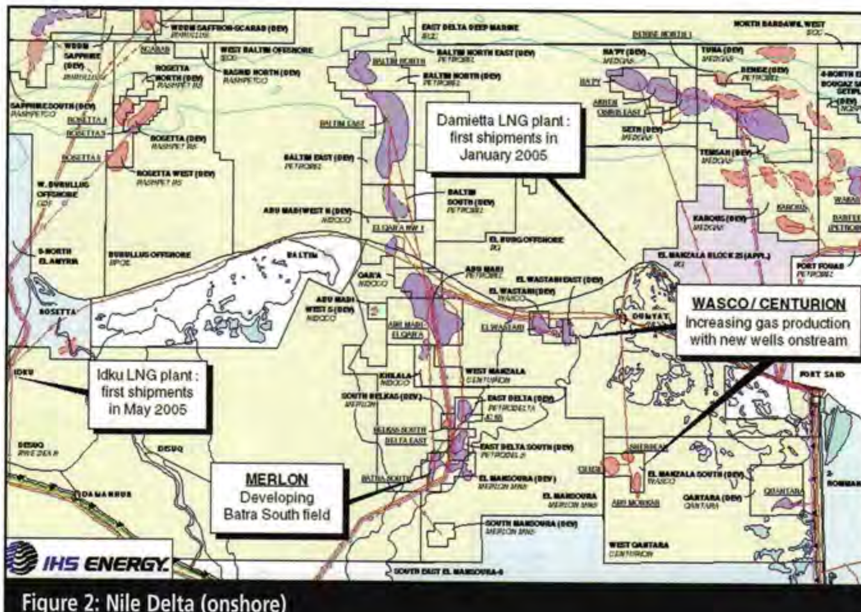


Figure 2: Nile Delta (onshore)

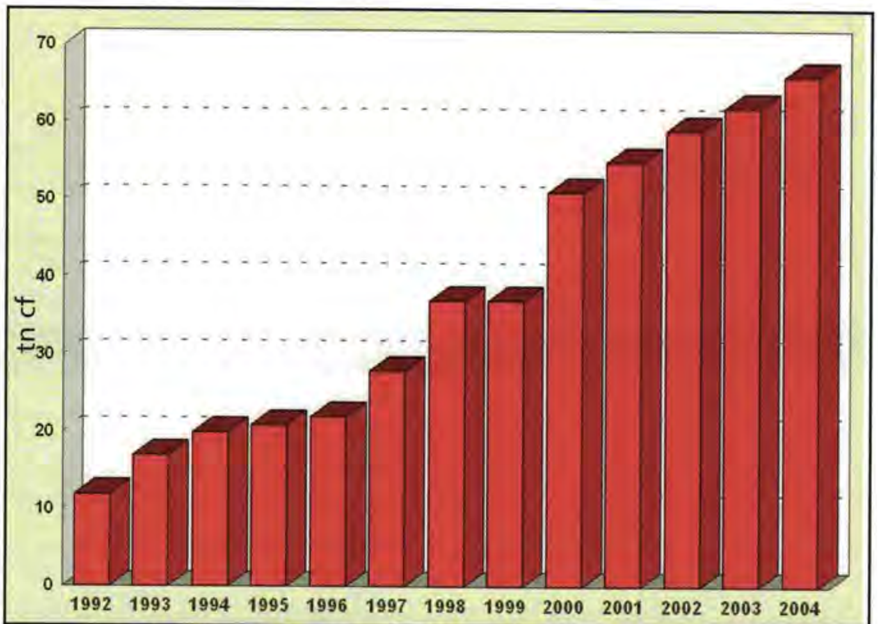


Figure 3: Egyptian gas reserves (in tn cf), 1992–2004

was received to the recent bid rounds organised by EGPC and Ganope. On 3 February 2005, EGPC announced the winners for its 2004 Licensing Round. Eight companies secured 11 blocks – six blocks in the Gulf of Suez and five in the Western Desert/Nile Delta region. A total of 35 applications had been filed for 11 blocks by 22 companies or groups of companies, consisting of 20 applications for six blocks in the Gulf of Suez and 15 for five blocks in the Western Desert.

The winners were Apache for N El Diyur; Arabian Oil Company for NW October; Burren Energy for the North Lagia block; Devon for North Qarun and South October; IEOC (Eni) for East Obaiyed, North Bahrein and West Sidki; IPR-Transoil Corporation for the North Ramadan block; Lundin Oil for the SE Warda block; and Merlon Petroleum for SE El Mansura. In addition, Burren Energy was the winner for the North Hurghada block in the offshore Gulf of Suez. This block was one of the five blocks offered by Ganope El Wadi Petroleum Holding Company (Ganope).

Well prepared

North Africa is enjoying increased levels of both licence and drilling activity and, with Libya yet to fully emerge from the shadows of sanctions, it is Egypt that is proving the most active, and certainly the most prepared, for a future that will be more gas than oil.

And finally...

Philip Algar then, in 1971... and now

Philip Algar's first article in an oil publication appeared in Petroleum Review in 1971. Some years later, he was appointed Editor of the magazine, before becoming a freelance writer. Now, as he retires from journalism, we carry his last article in which he offers some personal views on future problems that the international oil and gas industry will have to face.

Since my first article, hydrocarbons have powered an increase in economic activity and standard of living for many millions that few could have anticipated. Those involved, who have overcome many economic, technical, financial, environmental and political problems, deserve our thanks.

Paradoxically, an industry that has achieved so much for so many is widely reviled – partly, I suspect, because of corporate arrogance. Whatever the reasons for this sustained hostility – and much rubbish is aired by ignorant critics, often backed by an ill-informed media – one consequence is a difficulty in attracting intelligent young people to the industry. This problem, first noted some time ago, but which prompted an inadequate reaction, is now becoming serious. There will also be difficulties in securing balanced discussions with governments and other organisations, and this is crucial if new supplies are to be exploited and new infrastructure built.

Demography

It is widely agreed, not least by the industry itself, that primary energy demand will increase by about 50% over the next 25 years – propelled by substantial population growth in the developing countries and the global desire for improved living standards. The centre of gravity of the international sector will surely move east.

We have seen the impact of Aids/HIV in Africa, but will any unexpected 'natural' disaster, such as bird flu, devastate numbers further? We can confidently predict that everyone on this planet now will be dead in 100 years... or can we?

What about ageing populations in the west and the implication for energy consumption in a region that will have to increasingly compete with others for imports? Over the last century, life expectancy in Western Europe has doubled to more than 80 years and continues to increase – but some European countries could see declining populations, notwithstanding immigration.

Energy supply and demand

Oil depletion has now become a subject that can be mentioned in polite society, despite the ill-informed preaching of some pseudo-academics. Even those remaining in denial must eventually accept that the world still relies heavily on elderly fields that cannot maintain today's levels of production indefinitely. Annual demand cannot outstrip discoveries for too long. Can new technology, in both the upstream and downstream sectors, save the situation? Will unconventional oil fill the potential void? What are the implications of the increasing reliance on heavy crude? Will natural gas be equal to all the optimistic forecasts?

As ExxonMobil has noted, 80% of the oil required in 2030 will originate from new production. For as long as some groups are reluctant to invest adequately, especially in relation to current profits and anticipated demand – ExxonMobil's 2004 profits were more than three times the gross domestic product of Bolivia, while Shell made £1mn per hour – there must be concern regarding the source of future supplies in the medium term. Opec, which has not invested substantially of late, should be able to supply significant volumes of new oil. But can it? Will it? Will the necessary new investment in Opec member countries, not least by big energy groups, be permitted?

As non-Opec output fades gradually, it is likely that fewer countries will supply greater proportions of global oil for which there will be increased competition. Indeed, world production of conventional oil could peak within 10 years. At a time of record profits, high prices and the most sophisticated technology ever, some groups, doubtless disappointed by their market values, are buying back their shares rather than spending more on looking for new oil. Others continue to purchase competitors and their reserves, rather than look for new oil, and some analysts remain unconvinced on the reliability of reserve-reporting systems.

Unsurprisingly – and geology and politics are partly to blame – significant new finds are rare. Presumably, many companies think that today's price levels will not be sustained and fear that an economic slump will force prices down, again, to unacceptable levels. They remain reluctant to invest upstream until further evidence is available and, by then, it may be too late to prevent another price rise. Additionally, many groups use a price around \$20/b as their economic test, which seems bizarre. Admittedly, near single figure crude prices have been followed by levels around \$50/b, but, surely, there will not be a precipitous and sustained decline to, say, less than $30/b, in the absence of a major catastrophe? Has the sector forgotten that it is part of a long-lead time, capital-intensive industry?

Furthermore, the sector's apparent infatuation with the short term, prompted partly by some naïve, inexperienced but influential analysts, bodes ill in a long-lead time industry. Looking long-term, my critics will point to unconventional oil and, possibly renewable energy – yes, but that takes investment and time, and the real problem is moving from here to there with as little dislocation as possible. The current high prices could easily soar yet further before slump sets in as demand reacts.

Today's high prices and the trend over the last three years – which, mainly and significantly, are the consequences of supply and demand problems not political disruption – reflect an inadequate infrastructure. Elderly, single-hull tankers that are being phased out because they no longer meet today's specifications, are not being replaced fully by newbuilds. Refinery capacity creaks at utilisation levels around 90% plus, while permitting and environmental factors mean that little new capacity is being constructed. Indeed, the spare money that the sector has – in what its inmates describe as a 'golden era' – is spent on producing ever-cleaner fuels. Pipeline distribution systems, especially in the US, also need to be augmented.

Supply and demand, of course, will always be equal – but what matters is the price at which they balance and the degree of pain in making the adjustment. Seemingly, the market has not yet delivered the right pricing signals to influence investment. Thus far, high oil prices have not affected economic activity, but any downturn in the economies of, for example, China, India or the US, could have global repercussions. In the near future, will the US current account deficit continue to rise and will the value of the dollar, in which currency crude oil is priced, continue to fall? Will Opec, once again, seek to price oil via a basket of currencies? For how much longer will the US consumer, increasingly dependent on borrowing, continue to spend? Under what circumstances would overseas nations slow their investment in the US? Will the increasing role of Opec prompt the organisation to introduce a new pricing structure or will it be content to rely on overseas futures exchanges?

It is unlikely that over the next two decades renewables will be significant globally, notwithstanding environmental reasons. Ironically, the same pressures could prompt renewed interest in nuclear power. In the UK, without any new projects, the percentage of electricity generated from this source could plunge from around 25% today to just 7% in 2020.

Politics and environmental factors

The oil sector influences and is influenced by external factors. Will the Middle East, holding about two-thirds of the world's proven oil reserves, be peaceful? Will Iraq eventually embrace full democracy of the form 'required' by some western countries? Furthermore, would such moves destabilise other, key, non-democratic oil-producing states in the region? One seldom-mentioned topic is the area's need for water. As populations increase, could that induce conflict that disrupted oil interests? Furthermore, should we accept the proven reserve figures in those countries where there has been substantial extraction and minimal discoveries? Should we be concerned that 85% of the world's identifiable hydrocarbon base is controlled by state companies? Will Russia, often perceived as the saviour of oil supply, retreat further into its political past, with implications for western investment? Will the Yukos affair affect the level of confidence in those western companies not yet investing in Russia?

Terrorism is a major, unquantifiable reality, not least in a sector where the assets are particularly vulnerable. Yet, oddly, some widely-available publications highlight potential weaknesses in the system and even offer advice on how to make bombs. However, leading international scientists maintain that global warming is a more serious threat than terrorism. The developing nations are not participants in the Kyoto treaty and the US shuns its implications, so what are the prospects? Evidence of global warming is being presented, almost daily, by competent scientists. Surely, it is time to heed their message and to take some genuine, urgent and practical steps, however painful, rather than risk nature's wrath in the future? Why do we assume that any measures taken now will, automatically, reduce economic activity? Let's ignore the views of 'celebrities' whose scientific knowledge is minimal and cease attributing the same value to their utterances as those emanating from qualified and experienced scientists.

Throughout its long history, the industry has faced major challenges – the future will be no different. Thanks for a fascinating career. That's it, there's no more. ●

Wireless alternative for reservoir monitoring on land

Discussions on reservoir monitoring have traditionally tended towards offshore fields, since these are typically higher value investments and, as such, can justify greater resource allocation. As a result, nearly all recent developments in monitoring or data acquisition technologies – such as permanent monitoring, fibre optic distributed temperature sensing or 4D seismic – have been driven by high value, high flow rate, offshore wells. However, the Expro Group has developed wireless gauges that are claimed to have the potential to provide cost-effective surface read-out data for land wells. Francis Neill, *Cased Hole Business Stream Director, and* Brian Champion, *Manager–Wireless Well Solutions, report.*

In spite of downhole permanent monitoring having been accepted technology for over 10 years, the number of installations on land has been very limited to date. Land wells have historically had to make do with intermittent gauge surveys or production logs – and then only in a small fraction of the total producing well population. Economic models have rarely been able to sustain a permanently installed monitoring system with total installation costs in the region of $250,000.

However, the fundamental principle of reservoir management remains the same whether the wells are offshore or on land. A key component of reservoir management is obtaining the data to make the correct decisions, in other words – reservoir monitoring. At a time of rising commodity prices and increasing concerns about long-term deliverability and accurate reserves determination, this raises the question as to whether there is an economic case for improved reservoir monitoring on land. This is dependent on two issues:

- A reservoir monitoring system with sufficiently low 'total' cost to become economically justifiable.
- Personnel and systems within operating companies to use the data and make decisions on the basis of it.

In some ways the second issue is the most critical. Many fields have virtually no well reservoir data apart from occasional surface measurements. Wells and fields have been produced this way for a century. However, there is little point in acquiring reservoir data unless it is going to be used to make decisions to optimise the performance of the reservoir. Therefore the question arises: 'If a cost-effective reservoir monitoring system is available, will operators have the resources to use the increased data and will they be able to justify the data acquisition by improving reservoir management?' Until a more cost-effective reservoir monitoring system is available, it is probably impossible to answer this.

For reservoir data acquisition there

In the spotlight

Expro Group's Cableless Telemetry System (CaTS)™ and its Subsea Safety System received awards as part of this year's Offshore Technology Conference (OTC)* 'Spotlight on New Technology' programme, which recognises the most innovative and significant offshore developments during the year.

CaTS™ is a revolutionary development in the field of reservoir monitoring and control that allows real-time information to be transmitted from downhole without the use of cabling or wireline in the well. Its two-way transmission capability enables the remote control of downhole instrumentation, opening the path to the radical redesign of downhole completions.

System integration testing underway on subsea controls

The Subsea Safety System technology, or landing string system, delivers critical well control functions in challenging oil field development conditions of up to 15,000 psi. Expro's range of landing string systems and controls are specifically developed to minimise risks in subsea completion and intervention operations and achieve secure well status in the event of an emergency. The systems are compatible with all horizontal subsea christmas trees and are qualified for use in water depths of up to 10,000 ft.

**OTC was held in Houston, 2–5 May 2005.*

are two options available today:

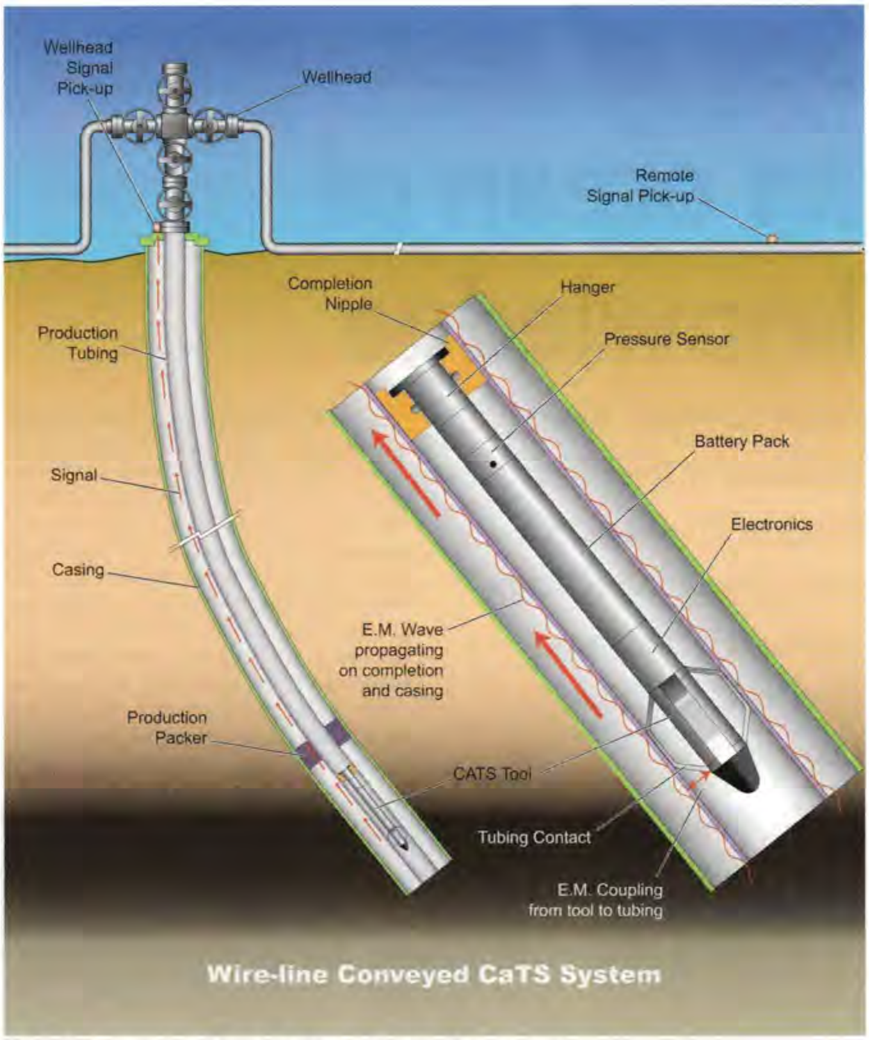
- Periodic wireline surveys with slickline or electric line, which require an intervention in the well with the associated operational costs, issues and risks. These surveys either produce a snapshot of the reservoir at that moment in time or, in the case of long-term memory surveys, produce data over time, but not until the gauges are recovered. This does not allow real-time decision making.
- Permanently installed surface read-out systems run with the completion. While the costs of these systems have been decreasing, the need for cabling, clamps, wellhead penetrators and surface equipment, plus the increased rig time required to run the systems, means that the cost will never decrease to the levels required to address the majority of the land market.

Breaking the cost barrier

However, there is now an attractive solution to the current cost barrier. Wireless gauges available from the Expro Group present an alternative that has the potential to provide cost-effective surface read-out data for land wells. A wireless gauge can transmit pressure and temperature data from downhole without the need for cables, either permanent or temporary. No wellhead feedthroughs are necessary and, by using the flowline as a signal transmission medium, the signals can even be picked up at a location several kilometres away from the wellhead.

Gauges can either be run as part of the completion or retro-fitted on wireline. Due to the technology constraints and the fact that the gauges are battery powered, wireless gauges do not transmit at high data rates. More typically, the gauges are set up to transmit a couple of data measurements per day for several years. However, in most situations, getting a single bottom hole pressure a day for three years is a significant improvement over no data at all. In addition, where more regular pressure measurements are required – such as during a well shut-in for pressure build-up – the tool can, on request, record the data and transmit it over time to surface.

Wireless technology is now field proven to depths in excess of 12,000 ft. In addition to standard installations for monitoring reservoir pressure and temperature, the technology is finding new, non-standard applications in reservoir monitoring. In the Far East, a client wanted to monitor reservoir performance beneath a beam pump. By monitoring the reservoir pressure, they could optimise the operating envelope of the pump and thus maximise system efficiency and reduce the lifting cost. Other technologies had been tried, but were either too costly or suffered from the noise effects of the pump. During a workover, a wireless gauge was installed below the pump close to the producing zone. The wireless gauge successfully transmitted during pump operations, enabling optimisation of the pumps.



General schematic of CaTS (cableless telemetry system)

In West Africa, the flowline transmission capabilities of the system were used to overcome security challenges associated with wellsite equipment and operations. Incidents of vandalism and sabotage were common and the removal of wellhead instrumentation was a real possibility. A retro-fit wireless system was installed in the well using standard wireline equipment. The gauge was programmed to send readings every six hours initially and then weekly for a period of up to three years. The signal from the gauge was transmitted up the well completion to the wellhead and then along the flowline to a secure gathering station located 5 km away from the wellhead, where the data was recorded and stored for the client.

A client has also used wireless gauges in the Rocky Mountains to carry out long-term interference testing between wells, thus allowing the client to optimise well spacing in a tight gas environment. Initial installations were in an abandoned well with gauges hung below bridge plugs in each zone. The impact of nearby producing wells could then be monitored. Installations are now planned on a newly drilled well with the gauges installed on the outside of the casing to record the reservoir pressure in unperforated zones.

Multiple systems can be installed in the same well, meaning that applications can include installations in multilaterals to measure the pressure in each leg. Similarly, wireless gauges can be installed at points along a screen in a horizontal well. As soon as you remove the need for cabling, the potential applications – either completion deployed or retro-fit – become numerous.

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Sea of resources, an ocean of knowledge

Louise Kingham, *Chief Executive of the Energy Institute (EI), provides a brief review of the recent Offshore Technology Conference (OTC) in Houston.*

'Sea of resources, an ocean of knowledge' – this was the theme of the 2005 exhibition and conference and it was a theme fully explored during the first week of May. OTC, the most renowned of offshore technology events, provided energy professionals with much exercise for the mind and the body as they strolled the length of several football pitches to soak up the information provided by 2,087 exhibiting organisations from 32 countries including, for the first time, the Energy Institute (EI). Some 660 of the exhibitors were from outside the US and the UK had the largest coordinated country delegation presence – thanks to UK Trade and Investment and the Energy Industries Council.


OTC provided a perfect opportunity for the EI to meet new and existing members


Louise Kingham with Brian Morr, Chairman of the Houston Branch

Delegates from 110 nations visited OTC, which showcased numerous technology solutions for the industry and ensured that all the key issues of the moment were fully discussed in parallel sessions throughout the week. Of these, two conversation points regularly highlighted were concerns over the 'sea of resources' in terms of available future workforce and available future oil supplies.

Having worked with Chairman, Brian Morr, to set up the Houston Branch of the EI during 2004 (see *Petroleum Review*, July 2004), this was the event to celebrate the first anniversary of the Branch and tell all that we were open for business and ready to welcome new members. For EI members and guests, OTC week began with a reception hosted by Judith Slater, British Consul General, at her residence in the centre of Houston. Guests and members mingled on a warm spring evening, as Judith welcomed us all and, in brief speeches, both she and I announced ourselves to be – somewhat cheekily – OTC virgins!

Professional ethics

OTC week *per se* opened at 7.30am Monday morning with a fully attended breakfast meeting on professional ethics, targeted at engineers. Guest speaker Patricia Galloway, Group CEO of Nielsen-Wurster Group, asked those present to consider their performance and commitment against codes of conduct they had signed up to as members of professional societies.

Given that maintaining a professional engineer's licence in Texas calls for monitored commitment to the ethics requirement, this event was timely. But this was not what drove a high attendance as participants considered the latest thinking to address the diverse challenges of corruption and bribery, and the integration of sustainability into everyday engineering practice.

As I looked around the room at the assembled audience, seeking out the next generation of engineers, I was troubled to see that many in the room would be likely to retire within the next 10 years. I was not the only one having this thought and as the week progressed the theme of where our next generation of energy professionals will come from continued to develop.

Safety first

The impact made by and upon people in the energy industry was addressed again on Tuesday morning, with OGP's launch of its latest Safety Report. Although it was with disappointment that fatalities in 2004 had increased (by nine) on the previous year, the long-term trend showed an improvement in the fatal accident rate. In addition to fatalities, the analysis of 2.3bn work hours of data covered lost-time injuries and total recordable incidents reported by 37 companies working in 78 countries. Other emerging trends showed that regional differences in safety management performance were reducing, as was lost-time injury frequency – the latter demonstrating the effectiveness of increased management time given to managing work place safety.

OGP called for more attention to better performance and a reduction in the number of incidents with a low risk of occurrence but a high consequence of fatality. Further information is available from the OGP website at **www.ogp.org**

Key issues – supplies, data and reporting

The impact and involvement of people in the industry was one of several key topics discussed at various events during the week, including the keynote presentation by Matt Simmons of investment company Simmons and Co International. He ended his speech entitled the 'Big Surprise' by stating that none of his commentary on events of the past 12 months should have come as a surprise to any industry executive. He also called for collective data analysis between companies to ensure that there were no future surprises lurking as a result of imbalances between oil supply and demand.

Round-up

Peter Robertson, Vice Chairman of Chevron captured the essence of OTC 2005 well in his luncheon address at the Awards presentation. He spoke of the 'foresight, cooperation and technology' that the oil and gas industry needs to muster as we move forward beyond the era of 'easy energy'. What was unique about the present, he said, was that a number of challenges which were not new to the industry were occurring simultaneously. That was the new challenge – to respond to these at once by measuring up on the deployment of technology, capable people, established and new partnerships, and taking conservation programmes up by several gears.

To get in touch with the EI Houston Branch and to participate in Houston events throughout the year, please contact Branch Chairman, Brian Morr, e: **brian.morr@t-sphere.com**

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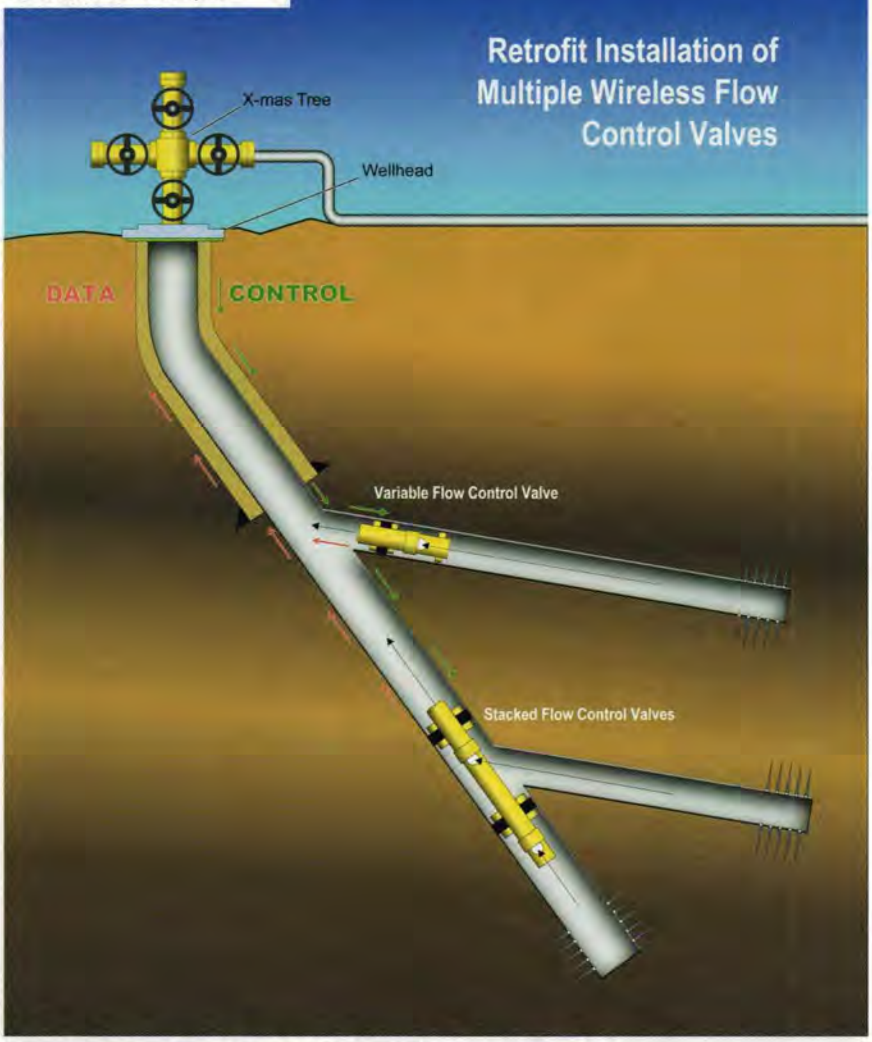

Retro-fit installation of multiple wireless flow control valves

System cost

What system cost will the market sustain? Obviously, this depends on the production from the wells and the benefit of improved reservoir management. At the lower end of the spectrum, being able to optimise beam pump wells using pressure below the pump would be nice – but how many wells will justify any additional expense at all? Discussions with operators have indicated that system costs of between \$10,000 and \$50,000 will be necessary to address the land market. If the cost is nearer to \$50,000, the market will be smaller; if it is closer to \$10,000, it is potentially very large. These costs equate to increasing overall production of the well over its life by between 200 barrels and 1,000 barrels to recover the investment at today's prices.

Today, a total system cost including installation of \$10,000 is not achievable with wireless gauges. However, with sufficient volume and suitable supply chain initiatives it may be possible to get close to this cost in the future. By eliminating the fixed and installation costs of a traditional permanently installed system, the wireless system is inherently less costly. Innovative commercial models such as rental of gauges or 'pay for data' may also help to increase operator acceptance in years to come.

The majority of the world's onshore oil and gas production is now 'mature' and has passed its production peak. As new opportunities to replace this production become harder and harder to find, it is now time to ask how can overall recovery factors from these mature fields be increased? The Middle East, North America, Russia, North Africa and Latin America all have large numbers of wells and fields that would benefit from improved reservoir data. In these mature producing areas, wireless reservoir monitoring technologies may provide a means of cost effectively acquiring the critical data that will allow operators to more effectively manage and optimise their production.

Going with the flow

A connection between the ancient Greek sculptor Praxiteles and a production platform offshore of Sakhalin Island may be an unlikely link – but it exists. Maria Kielmas *explains.*

In early February of this year the Archaeological Museum of Olympia in Greece, which houses Praxiteles' famous seven-foot marble statue of the messenger god Hermes with the infant Dionysos (left), announced that the sculpture had been equipped with friction pendulum bearings which would enable it to withstand strong earthquakes. Friction pendulum bearings were first developed by researchers at the University of Buffalo in New York State and manufactured by Earthquake Protection Systems of Vallejo, California. They permit a structure, or a component of a structure, to swing like a pendulum during an earthquake rather than resisting the movement rigidly with the result that it either breaks or falls. These devices have been installed below a reinforced concrete base upon which the Hermes statue stands. Although this technology has been proven in earthquakes for over 15 years, it has never been used offshore – until recently, on the production platform offshore Sakhalin Island.

Designed to withstand other hazards such as sea ice and typhoons as well as earthquakes, the $12bn Sakhalin project has become the focus of growing protests about its impact on the environment of what was, up to the last century, a penal colony. The region has had its fair share of natural disasters. In 1995 the northern city of Neftegorsk was flattened by an earthquake which killed an estimated 2,000 people. Earlier, in 1952, a 20-metre tsunami following an earthquake hit the island of Paramushir in the Kurile chain, wiping out the town of Severo-Kurilsk and killing more than 2,300 people. The aftermath of December 2004's Sumatra earthquake and subsequent Indian Ocean tsunami has heightened the awareness of such risks.

In contrast to the huge toll in human lives and private dwellings, the oil and gas industry escaped quite lightly in the December event. For example, the ExxonMobil-operated Arun LNG plant and port at the tip of Aceh escaped serious damage, as by the time the tsunami wave arrived there it had expended a lot of its energy and was no longer as large. However, as Wimpi Tjetjep, Chief of Research and Development at Indonesia's Mines and Energy Ministry, points out, this was 'just luck'.

Seismic isolation

The authorities in the Sakhalin region are worried because there is no sufficiently developed warning system for earthquakes and tsunami. When the Soviet Union collapsed many of the seismologists in the region lost their jobs and turned to fishing and market gar-

Statue of Hermes
Source: Archaeological Museum, Olympia, Greece

dening, while the seismic stations that do remain, do not have modern communications equipment.

However, the Sakhalin oil and gas projects are in a different situation – not only are they effectively isolated economically from their surroundings, their engineering design and friction pendulum bearings isolates them physically too.

London-based engineering company Arup first proposed the use of 2-metre diameter friction pendulum bearings at Sakhalin I to minimise seismic loads to the topsides, explains Zygmunt Lubkowski, an associate at one the firm's divisions, ArupGeotechnics. Arup had been appointed to undertake the front-end engineering design (FEED) for the system, together with Norway's Aker Kvaerner. The bearings are normally stainless steel concave dishes attached to the bottom of the topsides, sitting atop a holding plate. During ground shaking the topsides are allowed to 'swing and return', with the energy absorbed by the friction between the plates rather than damaging the top structure.

Lubkowski calls this a version of a 'seismic fuse'. Arup employed a similar philosophy for its design of the concrete gravity substructure (CGS) at the Malampaya gas field offshore the Philippines. The design problem here was to deal with uneven ground as well as seismic loading. The final concept involved installing a series of humps on the seabed that would allow the platform to slide in a controlled manner in both a strength level earthquake (SLE) and ductility level earthquake (DLE). A SLE is defined as one that has a reasonable likelihood of not being exceeded during the structure's lifetime, with a recurrence interval of between 200 to 500 years. A DLE is defined as the maximum credible earthquake at that site, with a return period of some 10,000 years.

According to Arup the peak ground accelerations for SLE and DLE events were 0.11 g and 0.38 g respectively. In addition, the deck connections used for the Malampya CGS were specially designed to further reduce the magnitude of seismic loads transmitted to the topsides from the substructure, and hence minimise the effective mass of the topsides (see **Figure 1**). Such a 'seismic fuse' can lead to a maximum lateral displacement of the topsides under earthquake loading of between one half and one metre. 'But people on the topsides will probably not feel a significant amount of movement,' Lubkowski says.

Interacting elements

The key to earthquake resistant design today, explains Lubkowski, is to understand how all elements in a project interact. Previously, a seismologist would analyse the earthquake risk at a given location, while a geotechnical engineer would worry about the foundations, a structural engineer would design the buildings and a mechanical engineer would take care of the equipment. The result usually was an under-conservative design for the foundations and an over-conservative design for the structures. In an earthquake the various elements could come apart – as happened to fuel storage tanks after the 1997 Izmit earthquake in Turkey (see **Figure 2**).

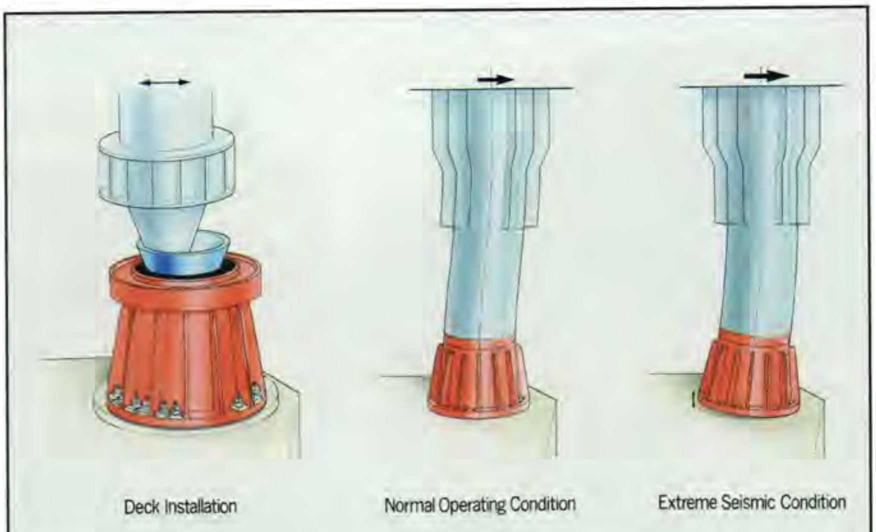

Figure 1: Malampaya concrete gravity structure *Source: Arup*

Today, the challenge is to model the expected earthquake performance of the entire system – soil, structure, topsides and equipment. Such 'performance-led design', which provides for greater efficiencies, is the aim of Arup and other engineering groups. The oil and gas industry – and the developed world in general – has the knowledge and resources to design and build earthquake efficient structures which fulfil their primary purpose, namely, to protect human life. But experience over the past decade, such as the aftermath of the 1995 Northridge earthquake in California, has shown that although the loss of life was not high, the economic downside was very significant.

So, such a performance-led approach was paramount in Arup's design for two storage tanks for the Port Fortin LNG project in Trinidad. The tanks were to be founded on a raft of piles and located in a moderate to highly seismic region where the safe shutdown earthquake (SSE) had a peak bedrock acceleration of 0.55 g. The principle issue in the design of the tanks was the liquefaction of saturated cohesionless soils under the tank. Initial attempts to improve the structure of the ground using stone columns were unsuccessful, so the tanks were designed to allow for liquefaction. The analysis modelled the interactions between the soil, piles, tank structure and LNG. The eventual foundation solution for each tank consisted of about 1,200 steel tubular piles, each 0.6 cm in diameter. As a result there was a two-fold cost-saving – expensive remediation was removed from the project scope and, secondly, isolation of the tank due to liquefaction reduced the loads used for the design of the tank and outer containment system.

Pipeline problems

The design of pipeline systems to withstand earthquake forces poses a multitude of problems. Such projects are rare and consequently acquire a high public profile as well as criticism and opposition from various advocacy groups. Such is the opposition to the oil and gas pipeline planned to cross Sakhalin Island.

However, of those pipelines which have been constructed over the past four decades, only two have been affected by severe earthquakes – and with diametrically opposite results. In March 1987 two earthquakes of magnitudes 6.1 and 6.9 on the Richter Scale, with epicentres 100-km north-east of Quito, Ecuador, ruptured a 70-km sector of the trans-Ecuadorian oil pipeline as well as the only road between the Oriente oil region and the capital. In November 2002, the Trans-Alaska Pipeline System (TAPS) survived the 7.9 magnitude Denali earthquake, the largest in North America for almost 150 years.

According to Tom O'Rourke, Thomas Briggs Professor of Engineering at Cornell University, Ithaca, New York, who inspected the damage after the

Figure 2: Burnt storage tanks and pipes at the Tupras refinery following the August 1999 Izmit (Kocaeli) earthquake in Turkey

Source: Earthquake Engineering Research Institute

Ecuadorian earthquake, much of the damage was incurred through a financial decision. 'They [the operators, at the time Gulf Oil] made a decision on economic reasons to build the pipeline above ground,' O'Rourke observes. Along its route from the eastern jungles to the Pacific coast this pipeline clung to the sides of mountain roads, vulnerable to sabotage and road accidents as well as natural hazards. The earthquake triggered landslides of poorly consolidated sandstones and volcanoclastics from the slopes of the nearby Reventador volcano onto the pipeline.

In Alaska, the 1,287-km long TAPS line was designed to accommodate 6.1 metres of horizontal and 1.5 metres of vertical fault displacement at fault crossing points. The pipeline crossed three faults – the Denali, McGinnis Glacier and Donnelly Dome faults. During the Denali earthquake the horizontal rupture offset at the fault trace was nearly 3 metres, with a total displacement of about four metres distributed across the fault zone. The pipeline was shut down for 66 hours after the earthquake so that the damage could be assessed and repairs made – also to guard against aftershocks. The pipeline had been constructed on special supports above the ground to allow for some fault displacement movement as well as allowing for general expansion and contraction of the pipeline in fluctuating temperatures. As a result, the earthquake caused just a little incidental damage to the support hardware (see **Figure 3**).

Figure 3: Denali fault, Alaska. Fault rupture by Richardson Highway beneath Alyeska pipeline. Red lines indicate location–direction of movement across fault. Pipeline N fault shifted W centre on horizontal sleeper rails

Source: Shannon & Wilson

Uncertainties

The total economic losses after the Alaska earthquake were some $60mn, mostly due to non-delivery of oil during the pipeline shutdown. The Ecuadorian losses were $1bn (money of the day); there were 1,000 deaths, mostly from the landslides; the pipeline was shut down for five months for repairs – the Ecuadorian economy has never fully recovered. This is why earthquake experts* advise that it is preferable to invest more money in site investigation to reduce uncertainty associated with natural hazards and so save on future costs.

While the TAPS pipeline crosses just three faults, the Sakhalin pipelines will cross 24 faults. However, if the faults are located correctly, the pipeline route may be planned safely, says Tom O'Rourke. 'If we get a pipeline to cross a fault at close to 90° we can design for a 20-ft lateral displacement,' he says. Design for the near-fault zone would be different. There are some 5 km to 10 km on either side of a fault zone where there would be a lot of shear and bending, where the ground will experience high velocity pulses.

Meanwhile, when it comes to buried pipelines, one of the greatest problems has been permanent ground deformation at vulnerable points. According to Tom O'Rourke, it is still not possible to model these effects given the complex rupture patterns that are created by even strike slip faults. There is also relatively little analytical work available for a pipeline crossing a normal or a reverse fault. This lack of fundamental knowledge on soil–pipeline interactions means that current engineering practice is still characterised by a very high degree of uncertainty, says O'Rourke. So, Cornell University has developed an advanced simulation project – the George E Brown Jr Network for Earthquake Engineering Simulation (NEES) – to evaluate the response of pipeline and other key lifelines under earthquake conditions. The results of these labours may well be used to protect works of art (such as Praxiteles' statue of Hermes) as well as oil and gas industry infrastructure and investments.

**'A framework for assessing earthquake hazards for major pipelines', Juliet Bird, Tom O'Rourke, Tony Bracegirdle, Julian Bommer and Iain Thomas, 2004. Paper presented at the 13th World Conference on Earthquake Engineering, Vancouver, Canada.*

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- *Government and national company regulators, contract administrators, advisors and policy makers.*
- *Accounting, tax, legal and banking professionals supporting E&P operations.*
- *E&P industry consultants, investors, risk analysts and project engineers.*

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Shocking revelations

James Cormier-Chisholm*

takes a closer look at national electricity grids and outlines a way to reduce energy consumption and worldwide greenhouse gas emissions, saving billions of dollars in the process.

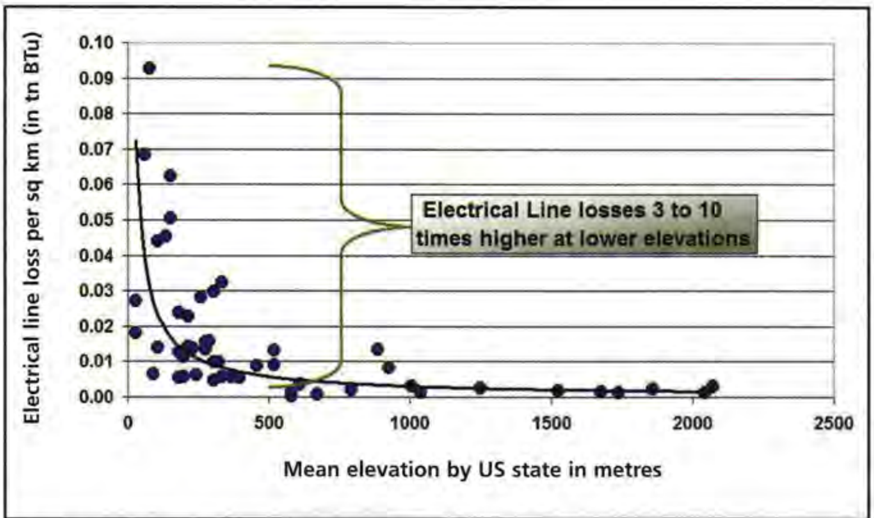

Figure 1: Power line losses versus altitude above mean sea level

Countries are wasting millions of tonnes of coal, natural gas and oil every year as power transmission lines have been placed in areas where they are exposed to conditions that promote the loss of electricity. Fortunately, however, there is an easy way to increase power line efficiency. The solution will not only lower fossil fuel consumption and greenhouse gas emissions, it will also save hundreds of billions of dollars and increase per capita income levels. And the fix can be applied now.

The issue of power line losses came to my attention in June 2004, when I was researching the reasons behind a series of blackouts in California. In looking at power line distribution data from the US, a surprising set of relationships was found which formed the basis of a new viewpoint on more efficient power distribution. These relationships were picked up by a nonlinear spline regression analysis.

Spline data mining is not new – it began as a drafting technique associated with boat building hundreds of years ago. As the computer age developed, mathematicians transferred this old, but useful, shipbuilding technique into mathematical formulae and algorithms for use in computer systems. By the 1990s, statisticians had developed spline regression analysis to model complex nonlinear statistical data.

Power line losses

When applied to power loss data, the technique uncovered a previously unknown statistical relationship between power loss and altitude above mean sea level. In addition, it picked up a second relationship between air moisture content and power line losses. Simply put, power lines have less power line loss in regions where there is less moisture, or regions that are at higher altitudes (see **Figures 1** and **2**).

Why does this correlation exist? Power line losses occur through a process called 'heat of resistance'. As electrons move through the wires, heat of resistance converts some of the electrical energy into wasteful heat. Resistance in the wires increases as air temperature increases – the hotter the air, the more electrical energy is converted into heat. As you go lower in altitude, air temperature generally increases, as does power line loss. Most of this loss occurs at altitudes below 400 ft above sea level. By simply shifting power lines above this mark, power line losses could be reduced significantly.

Power line losses also occur through leakage – electricity leaks through line insulation into the air as a field of force around power lines. The amount of leakage rises as humidity rises. As can be seen in **Figure 2**, air moisture is positively correlated with wasted energy. By moving power lines away from bodies of water, power line losses could be reduced significantly.

Did engineers miss these relationships for over 100 years? Well, yes and no – ever since the first electrical grids were constructed, engineers understood that heat of resistance loss was a major waste in electrical energy transport. But heat of resistance was primarily understood as being linearly related to distance travelled. As a result, engineers optimised for distance between cities, towns and electrical generation stations – they made straight lines on a map and shaped the electrical grid accordingly.

However, those original power line loss studies assumed an ideal temperature of resistance, ignoring the fact that over large geographic distances, temperature and moisture content of air vary greatly. Engineers essentially took a lab value for heat of resistance and air moisture content, and projected this 'ideal' value over the entire electrical grid system. These rule of thumb values passed into textbooks and became ingrained engineering practice. In reality, power lines travelling through higher regional ambient air temperatures suffer higher heat of resistance than predicted in textbooks.

Paycheck impact

The power loss work led to an observation – in regions where power losses were highest, factories suffer higher costs for electricity on average. This means less money to pay workers. In contrast, people working for factories in regions where power losses are less tend to have better pay.

A further spline regression analysis was carried out to try to predict per capita income levels using the same input variables as used for power line losses – ie altitude of US States and the ratio of water to dry land by US State. The results correlated very closely, as seen by a comparison of predicted per capita income levels by US State to actual levels of per capita income (**Figure 3**). In other words, climate predicts power line losses and power line losses predict part of your paycheck.

What if power lines were put up higher? The analysis predicts a group average increase of $2,400 if all high-tension power lines were to be raised above 400 ft in altitude. The highest capital gain would be in New York State, increasing by $3,227 in average per capita income (highest income gain of all US States). The least income gain, at $1,374, is Louisiana. If we take all the income increases by US State across all States, and multiply these income figures by the working population by US State, an overall national income increase for the US of $352bn/y is possible.[1]

In addition, if you shift power grids to reduce losses by altitude and moisture, the same amount of electricity can be created using far fewer fossil fuels. The US Department of Energy predicts that the country will create 5,985mn tonnes of carbon dioxide (CO_2) emissions while producing electricity in 2005. Shifting the power lines could reduce these greenhouse gas emissions by approximately 13.8%, or by 831.1mn tonnes – more than enough to meet Kyoto Protocol guidelines.

Monetary savings would also be significant. If power lines were raised on average above 400 ft, the statistical formula predicts that reduced electrical wastage would produce a fuel savings of $98bn/y.

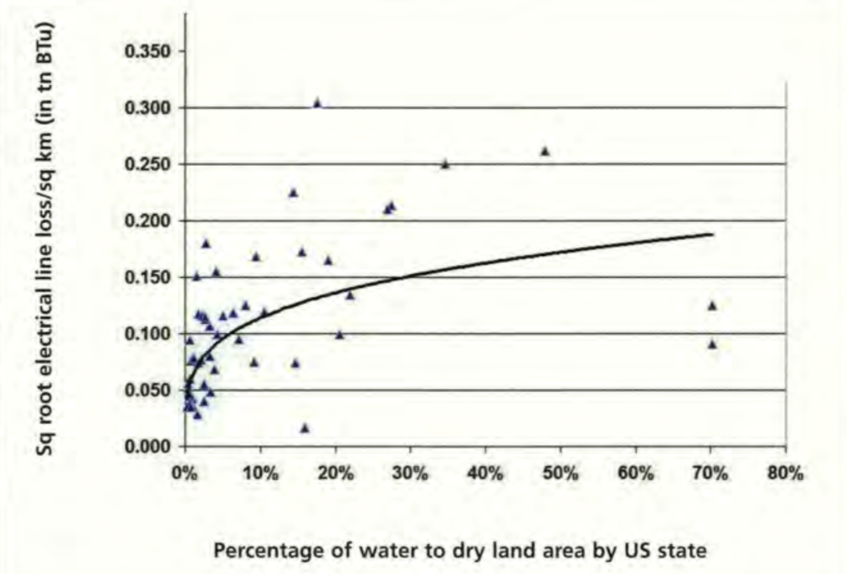

Figure 2: Ratio of surface water to dry land (as %) relates to power loss

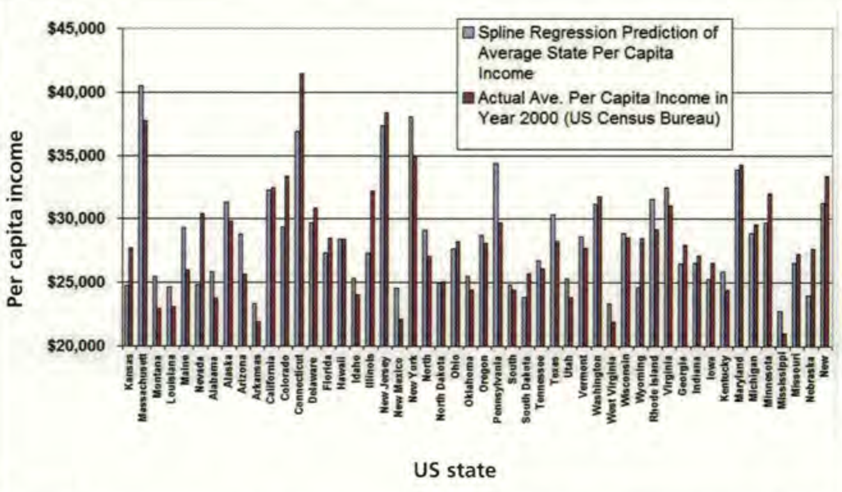

Figure 3: Regression spline analysis using altitude and ratio of water to land accurately predicts average per capita income levels by US State

The next step

So, what can be done? The easy answer is to simply shift as many electricity lines as possible so that they are located away from large bodies of water and above 400 ft in altitude. In the developed world, however, a lot of money has been invested into the existing power grid and it would be expensive to undertake such a task. Even though the advantages are obvious, it would also take several years to approve rights of way for new transmission lines. There is also the issue of political will.

Fortunately, the data points to 'low hanging fruit', where significant gains can be made quickly. The selfsame spline regressive data mining formula could also be used to map where these low hanging fruit are and indicate optimal new pathways for future power transmission lines.

As for the entire transmission grid, lines require periodic maintenance and much value can be obtained by simply raising their height. Longer term solutions, such as shifting lines away from the coast into hill country, promoting sectors of the economy (like Silicon Valley) that use a lot of electricity into higher altitude areas and shifting population centres to higher altitudes, can follow over generations. The Third World, which has a less-developed grid, can benefit from programmes that properly site new lines so that they benefit from efficiencies right from the beginning. Through applied knowledge, humanity can increase the efficiency of its electricity system, meet and exceed Kyoto obligations and save billions of dollars. All that is required is the will to act.

**Jim Cormier-Chisholm is owner of Data Forest Mining, a data mining consultant firm. He holds a degree in Geology and an MBA with specialisation in financial statistical data mining from Saint Mary's University. He has spent the past 13 years working for Environment Canada as a consultant and as a geoscientist for the mining industry.*

He can be contacted at e: **James_Chisholm@hotmail.com**

Reference

1. US Census Bureau, Working Population Figures by US State. Found at **www.factfinder.census.gov/home /saff/main.html?_lang=en&_ts=**

Integrated fuels supply management drives cost savings

New dynamics in the fuel markets are changing the way in which airline and freight companies procure and supply fuel to their fleets. In response, many companies are implementing new business initiatives, powered by innovative software, to drive significant savings in fuel procurement and supply management organisations. Dale St Denis, *Vice President of Solutions Marketing, SolArc*, reports.*

The airline industry has always been volatile and competitive, marked by numerous strikes, bankruptcies and mergers in its history. However, since 9/11 the industry has been subject to increased pressure to minimise working capital and improve cash flow in order to survive in the face of a decline in passengers and additional security costs.

There is also growing competition on the lowest cost-to-serve end of the market, resulting in even more pressure to cut costs.

These developments all drive the need for an integrated, comprehensive and auditable fuel supply management system. Fuel costs are typically the second largest cost driver for a transportation company, ranging from between 12% and 18% of total operating costs.

Even small changes in the price of fuel can have significant impact on an airline's projected earnings.

Volatile fuel prices and the current financial plight of most transportation companies require senior executives to aggressively monitor their company's earnings exposure to changes in fuel market prices.

Many companies are in the process of centralising fuel supply and market price information to enable timely and accurate fuel management decisions. Furthermore, as the transportation industry is forced to consolidate in order to remain cost-competitive, there is a heightened need to streamline payables management for fuels.

Managing the physical inventory

The dynamic fuel markets have driven transportation companies to change the purchasing practices and information systems used for fuel supply management. The fuel supplier is responsible for providing fuels according to aircraft or transportation equipment quality guidelines and maintaining fuel terminal inventory levels. The demand forecast is very dynamic, responding to economic factors, security alerts, capacity demands, weather and fleet availability/dispatch.

The fluidity of the demand forecast results in a business requirement for frequent updating of fuel supply plans for short, medium and long-term supply horizons. Fuel suppliers are challenged to provide accurate and timely supply plans because input data is often fragmented across multiple legacy source systems. Input data, including supply contracts, demand forecasts, in-transit shipments and actual terminal inventories are often manually consolidated and manipulated in a spreadsheet environment. The lack of visibility of shipment information drives excess inventory positions to avoid shortfalls. Even small reductions in average days of supply on hand can lead to significant reductions in working capital and associated carrying costs. For example, a 20% reduction in inventory provides working capital savings in the range of $500,000 to $750,000 for a 30mn-gallon fuel inventory across all regions served.

By using fuel procurement software, the fuel supplier can generate and update its supply plans to reflect the most recent forecast, supply commitments, in-transit shipments and terminal inventories. Such software solutions provide an automatic electronic interface for the fuel deliveries to the consuming fleet locations and assets, which provides a daily inventory level at all of the terminal locations. The actual daily inventory and value by location leads to informed decision-making on replenishment plans.

In addition to managing tighter inventories, software can also generate reports to analyse purchase cost by fuel vendor, average fuel cost by terminal and compare total laid-in costs against price indices. Historical reporting on fuel supplier performance and delivered fuel costs by location is available for supporting fuel contract negotiations and managing third parties responsible for fuel delivery to the equipment. Tracking and reporting fuel supply vendors' performance can lead to savings in annual contract negotiations on purchased fuels and services. For example, a 0.05% reduction in contract fuel price and corresponding improvement in payment terms provides annual savings in the range of $250,000 to $500,000 for a 1bn-gallon fuel purchase.

Fuel procurement software solutions make it easy for a fuel purchasing and supply organisation to manage and group fuel transactions automatically into a hierarchy of positions by fuel grade, location, supplier, individual buyer or specific sourcing strategy. A best available quantity function optimally selects among contractual, planned and actual volumes for use in inventory and position reports.

Fuel costs are typically the second largest cost driver for a transportation company, ranging from between 12% and 18% of total operating costs. Even small changes in the price of fuel can have a significant impact on an airline's projected earnings

Contract management cost savings

Fuel contract terms and conditions are supposed to be standardised. However, each supply organisation has its own version of the standardised agreement that must be accommodated. This forces the contract administration department to process many contracts off-system, especially complex supply agreements that do not fit the standard contract term and conditions. Legacy systems often are not flexible enough to accommodate the contract types that are used for fuel supply agreements, fuelling operations agreements or storage agreements. Some software solutions address this issue by centrally managing contract administration and transaction confirmation functions.

Fuel management organisations are focusing more attention on managing the payables process on contracted fuel volumes and qualities to ensure that they are paying the correct price and not paying a duplicate invoice or paying for fuel that was not received. This includes accurate calculation and payments of taxes on fuels to governing jurisdictions. However, in many cases, the invoice validation for supply contracts is only sporadically monitored using stand-alone spreadsheets that lack accurate information on originating contracts and received volume and quality. The opportunity for fuel suppliers to miscalculate a fuel invoice on a supply contract can be significant. For example, capturing and correcting invoicing errors on 0.2% of fuels invoices are worth approximately $750,000 to $1mn per year on an annual purchase volume of 1bn gallons of fuel.

A major responsibility of fuel schedulers is to manage and optimise the fuel contracts used to supply and deliver the required fuel at each location. Fuel procurement tracking software can help assist the scheduler in making cost-based decisions when considering different options of supplying fuels. Using this software, a scheduler can view delivery requirements for a known destination and run date, and view all logistics and supply contracts that are available from any origin to the selected destination.

These tools can identify the total cost, including the market price and freight cost, of transporting fuel from an origin to the selected destination. Using this process results in cost-based – instead of routine-based – decisions for the selection of contracts for fuel delivery. Savings associated with improved compliance can be significant. An improvement in supply contract and delivery option selection provides annual savings in the range of $250,000 to $400,000 on 1bn gallons per year of fuel supply.

Some software solutions include purchase and logistics contract templates to capture term and spot deals, and can be used to estimate and actualise fuel movements. A business process that includes an extensive contract capture functionality could allow users to manage complex contract flows from origination to destination, capturing all movement expenses, transportation fees and additional fees. Purchase approval workflow based on user-configurable limits is a critical part of the process in order to manage exposure to contract risk.

Contracts, amendments and other documents can be customised, based on a variety of purchasing variables and fuel specifications. Some software solutions offer advanced pricing and valuation tools for the unique pricing needs of fuel transactions, which allow users to access a specific index or multiple indices to price fuel purchases or to value fuel positions. This feature supports flexible date-tiering or volume-tiering and fixed-price or formula-based pricing for price and tax calculations around US and international jurisdictions.

Benefits for accounting

Many fuel procurement and trading software platforms provide advanced accounting and settlement capabilities, which make it significantly easier to enter, review, manage, value and reconcile fuel volumes on a daily basis. Their integrated architectures simplify and automate the monthly closing process as well. Payables matching tools are robust features that assist in the verification of third-party invoices and identification of potential inaccurate costs, preventing duplicate payments or overpayments. The ability to receive invoices via an electronic interface and automatically match to the accrued transactions significantly reduces manual labour and improves the ability to process invoices for timely payment.

In an integrated system, a scheduled movement of product feeds downstream accounting with the actualised (received) volume, eliminating redundant data entry and manual reconciliation. Having a single point of data entry drives significant labour efficiencies. A reduction in clerical time to re-enter shipment information and manually reconcile scheduled movements with accounting can deliver annual labour savings in the range of $150,000 to $350,000.

Tax modules within some programs can capture the tax rules for federal, state and local government, as well as all required certificates, licences and/or exemptions. This can enable a system to accurately calculate and accrue all taxes for payment and for reporting to the various taxing entities, resulting in additional reduction of labour costs.

Transportation costs, including terminal fees, throughput fees, inspection fees, import duties and other miscellaneous fees, are captured and tracked for payment. Some systems can interface seamlessly with existing ERP (enterprise resource planning) and accounting management systems, such as SAP, Oracle, and PeopleSoft, sending both invoice payment information and financially coded transactions.

Hedging against rising fuel prices

Transportation company earnings are exposed to changes in fuel prices. Therefore, a key objective is to achieve fuel price stability. To accomplish this, some transportation companies have made it a business practice to hedge their price exposure by trading oil derivatives and products. Effective hedging requires accurate and timely analysis of market-price exposure on fuel supply positions.

There are products on the market that use market-to-market reporting to value physical inventory, future supply commitments, deliveries and receipts, and financial deals against market price indices. In order to manage market risk, some solutions offer risk exposure grids, which help determine the financial exposure and profit and loss of a company's total fuel supply position, both physical and financial, at any given moment. Of these solutions, some also feature a hedging panel for a risk professional to create hedging transactions for fuel supply contracts including futures, options, swaps and other over-the-counter instruments. These hedging transactions can be used to hedge the original deal from which the hedging panel was invoked.

Some solutions also have the flexibility to allocate the hedging transaction across multiple fuel supply contracts. Significant savings in fuel costs can be achieved through effective hedging during periods of rising fuel prices. For example, a 50% hedged position with hedging contracts that correctly offset the increasing market price for jet aviation fuel at the US Gulf Coast during the period of June 2000 through June 2003, provides estimated savings of $25mn to $30mn on 1bn gallons of purchased fuel at market prices.

Making a critical choice

All of these business requirements point to the importance of a company having an efficient, central location to track its fuel supply and management activity. Several platforms today provide fuel buyers, supply operations, treasurers, risk managers and accountants the information needed to make informed decisions around their fuel management with the touch of a button. Many of these software solutions strive to provide a user-friendly application, which allows the user the ability to manage his fuel business in a fully integrated package from purchasing, through fueling operations to accounting.

Ultimately, these software platforms are designed to offer the flexibility to purchase and supply a variety of fuels, ranging from jet fuel, diesel and gasoline, using various transportation modes to supply multiple equipment specifications and locations. Choosing the right solution in today's competitive environment is one of the most critical decisions a company can make to ensure its long-term survival and success.

SolArc* (www.solarc.com**) *is a leading provider of supply and trade management solutions for global energy companies. Its flagship product, SolArc RightAngle, integrates deal capture, scheduling, inventory management, pricing, credit, accounting, position reporting and analysis in a single platform solution. SolArc's products work with existing information systems, including corporate ERP, credit management and risk management systems to provide customers with a flexible solution that leverages their existing systems' infrastructure.*

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Drinks reception: 12.15, Lunch: 13.00

Guest of Honour and Speaker
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Review of relationship between Cetane Number and Cetane Index

It is a requirement of the European Specification for Automotive Diesel Fuel BS EN 590 that both the Cetane Number (CN) and Cetane Index (CI) are determined and reported. This article, which summarises the findings of an Energy Institute (EI) sponsored Technical Development Project carried out by Cliff Lilley*, *outlines a review of the suitability of the current cetane index equation used in IP 380* Calculation of cetane index of middle distillates by the four-variable equation *(EN ISO 4264) (ASTM D 4737 procedure A**) for calculating Cetane Index, to predict Cetane Number as measured by IP 41* Determination of the ignition quality of diesel fuels – Cetane engine method *(ASTM D 613).*

Year	Bias Mean	Bias SD	Bias $RMSE_b$	CN/CI correlation	Best-fit slope	Trend line $RMSE_r$	CN range Min	CN range Max
2000	–0.6	0.7	0.9	0.96	0.88	0.7	47.8	56.4
2001	0.0	1.2	1.2	0.96	0.85	1.0	45.5	54.7
2002	0.3	1.4	1.5	0.96	0.83	1.2	44.3	57.6
2003	0.1	0.6	0.6	0.99	0.88	0.4	46.0	55.3
2004	0.6	0.8	1.0	0.97	0.92	0.8	45.3	54.1
00–04	0.1	1.0	1.0	0.97	0.84	0.9	44.3	57.6

Table 1: Trends in CN and IP 380/EN ISO 4264

The Energy Institute (EI) runs the IP Gasoline and Diesel Fuel Engine Correlation Scheme, within which approximately 24 laboratories world-wide determine Cetane Number (CN) by the IP 41 (ASTM D 613) method. Most of these laboratories also determine density and distillation recovery temperatures, thereby enabling the Cetane Index (CI) to be calculated according to IP 380. The sample fuels used in the correlation scheme are selected to represent production fuels with a wide range of CNs, thus providing data on fuels that meet the BS EN 590 specification minimum of 51 CN and the BS 2869 A2 specification minimum of 45 CN, and beyond.

Data sets

As the occasional fuel sample can have an undue effect on the trend between CN and CI, it is better to base any comparisons on larger data sets. This review looks at two ranges of data: the year 2004 and the five years covering 2000–2004. The former study period provides information on more recent fuels, whilst the latter provides smoother overall trends as it is less sensitive to individual fuels. The five-year study also provides year-on-year information. For the sake of brevity, the full monthly data for the five-year period are not given, but these are available from the EI.

Outliers and unusual fuels

For each fuel property in turn, the data were first checked for unusual individual laboratory results. Any outliers detected by Hawkins' test, according to IP 367 *Determination and application of precision data in relation to methods of test* (EN ISO 4259), were excluded from further analysis. Such outliers may be the result of laboratory bias or transcription errors.

The means of the data excluding outliers were then used to provide estimates of the 'true' values of CN, density and distillation recovery temperatures. The latter means were then used in IP 380 to derive the CI values.

The fuel samples for July 2003 and September 2004 contained cetane improver. The samples for August 2004 had T50 and T90 values outside their recommended ranges. All three fuels are thus outside the scope of IP 380, and have been excluded from these analyses.

Analysis

There are various ways to assess the suitability of IP 380 to predict CN. They include:

- Mean bias between CN and CI, defined as mean (CN–CI).
- Bias standard deviation (SD) – a measure of scatter about the mean bias.
- A trade-off between mean bias and bias SD, as measured by the root mean square error ($RMSE_b$) – that is square root of the sum of the squared bias mean and squared bias SD.
- Correlation between CN and CI, a measure of dependence between CN and CI.
- Bias trend in terms of the slope of the 'best-fit' CN/CI regression line.
- Data consistency, as measured by the root mean square error ($RMSE_r$) about the best-fit regression line.

It is not enough to do well in just one of the above. For example, an overall bias of zero could hide either a bias slope very different to the ideal CN=CI slope or a large scatter of CI about CN. Furthermore, a small $RMSE_r$ could hide either a large bias or a far-from-ideal bias slope. The precisions of the test methods involved imply that some scatter of CI about CN is to be expected. As this scatter is dependent on the choice of fuel sample, then bias SD and $RMSE_r$ will naturally vary over time. Therefore, IP 380 can be considered appropriate when (i) overall bias is close to zero, and (ii) overall bias SD and $RMSE_r$ are consistent with test precisions. The bias slope will usually be close to ideal when both (i) and (ii) are attained, unless the range of CN and/or CI is relatively small.

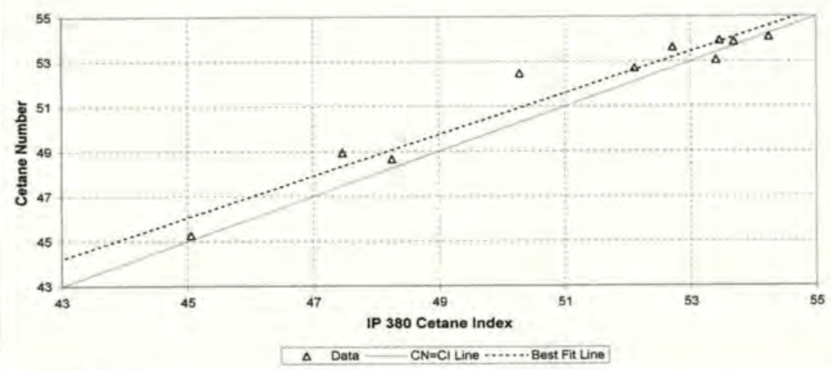

Figure 1: IP ST-B-1 data 2004

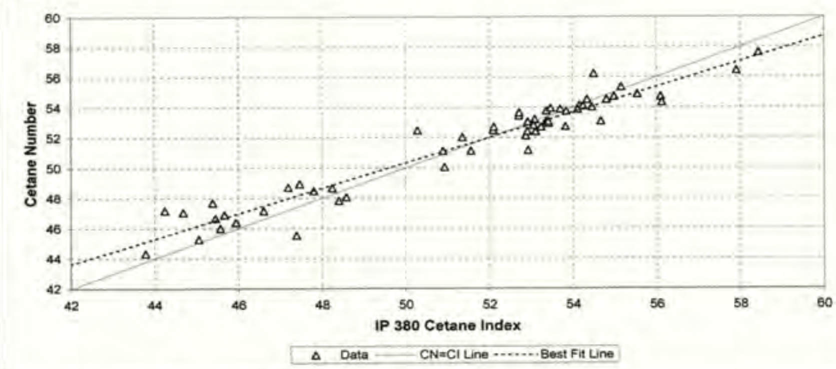

Figure 2: IP ST-B-1 data 2000–2004

Results

Trend information relating to CN and IP 380 is given in **Table 1** for all relevant dates. They are (i) mean bias, bias standard deviation (SD) and a trade-off between the two, (ii) correlation between CN and CI, (iii) best-fit regression slope between CN and CI, (iv) trend line $RMSE_r$ from the regression, and (v) the range of CN.

The CN/CI results are shown graphically in **Figures 1** and **2**. **Figure 1** shows the best-fit regression line through the 2004 data, and **Figure** 2 shows the best-fit regression line through the 2000–2004 data.

Points to note are :

- The overall IP 380 bias is small over five years, although this average hides the poor but opposite biases in the 2000 and 2004 data sets. Because mean biases per year are generally small, the various measures on scatter (bias SD, bias $RMSE_b$ and $RMSE_r$) tend to be very similar. The larger scatter of results in some years may be due to changes in fuel composition or to the occasional unusual fuel sample.
- Overall CI has a tendency to over-predict above 52 CN, and to under-predict below 52 CN. This has also been the case in recent years. The subset of low (<48) CN fuels in **Figure 2** may indicate a bias problem for fuels with very low CN.
- The IP 380 best-fit slope was worst in 2002. This reflects the risk of using small data sets. Over five years, the overall best-fit slope is usually better.
- For the fifth successive year, the CN/CI correlation was good, reflecting recent consistent data. The overall trend line $RMSE_r$ reflects the 'natural' variability in the fuel samples, with some years better than others. This is to be expected.

Conclusions

Three main conclusions can be drawn from this review:

- The overall IP 380 bias is close to zero when estimating CN. The noticeable biases in 2000 and 2004 look to be due to chance when selecting a small number of fuel samples.
- On average IP 380 estimates CN very well. The scatter associated with individual CN estimation fluctuates year-on-year, suggesting a random element.
- The equations used in IP 380 for calculating CI are satisfactory and do not require revision at this time. However, a bias problem may exist for very low CN fuels. The EI will continue to monitor the relationship.

**Cliff Lilley specialises in statistical analysis of data sets and runs his own consultancy – Cliff Lilley Consultancy.*

***It should be noted that ASTM D 4737 procedure B Cetane Index is relatively new and only applicable to fuels meeting the ASTM D 975* Standard Specification of Diesel Fuel Oils Grade 2-D Low Sulphur *requirements.*

If you would like further information about this article or the IP Gasoline and Diesel Fuel Engine Correlation Scheme, please contact the EI Library and Information Services
t: +44 (0)20 4467 7100
e: **lis@energyinst.org.uk**

Silver corrosion and compliance testing

The Energy Institute recently held a very successful workshop at its London offices on the two issues of silver corrosion by automotive fuels and testing for compliance with BS EN 228: 2004 research and motor octane number requirements. John Phipps *reports.*

The workshop, which was held at 61 New Cavendish Street on 3 March 2005, was attended by delegates from the UK, mainland Europe and the US.

Silver corrosion by automotive fuels

Presentations were made by J Crighton, N Elliott and H Read on:

- The background to the problem of the corrosion of silver components in the fuel level gauges in vehicle fuel tanks.
- The application of the IP 227 *Determination of corrosiveness to silver of aviation turbine fuels – Silver strip method* by various US States in their auto-fuel specifications.
- The work undertaken by the ASTM in conjunction with experts from the EI to produce a new test method based on the ASTM D 130/IP 154 *Corrosiveness to copper – Copper strip test* but using the silver strips and classification table from IP 227.

From the discussions it appeared that due to the problems of silver corrosion by auto fuel in the US, a number of refineries throughout the world were starting to test their products for silver corrosion to ensure confidence in product quality released. This being the case it was agreed that to have the method of test for silver corrosion embedded in the ASTM D 4814-04b *Automotive Spark-Ignition Fuel* specification was not the way forward and that the EI would produce a standard test method that could be used as the basis for either an international standard or European norm.

The workshop further agreed that certain sections of the silver corrosion test developed by the ASTM required changes to make it less ambiguous with regard to sampling and sample handling, to ensure that all faces of the silver strip get exposed equally to the test fuel and to tighten the way in which the results are interpreted and how the corrosion classification is reported.

It was agreed that the EI would continue to participate in the joint ASTM/EI activities looking at alternative techniques for evaluating the corrosiveness of petroleum products to silver.

Testing for compliance with BS EN 228: 2004 research and motor octane number requirements

The difficulties that had arisen regarding which dated test method was to be used to test petrol for compliance with the BS EN 228: 2004 specification requirements were outlined. The problem was that while the table of requirements and test methods for both premium and regular grade petrol stated that the prEN ISO 5164: 2002 shall be used to test for RON, prEN ISO 5163: 2002 shall be used to test for MON and 0.2 of an octane number shall be deducted prior to reporting, the National Annex stated that BS EN 25163: 1994 shall be used to test for RON and BS EN ISO 25164: 1994.

This had caused confusion as the 1994 test methods referenced the ASTM D 2699 – 1986 and ASTM D 2700 – 86 methods, whereas the 2002 test methods reference the ASTM D 2699 – 01 and ASTM D 2700 – 01 methods. This meant that laboratories did not know if they had to deduct 0.2 of a number irrespective of which test method they used to determine RON and MON.

The measures that the EI and UKPIA had taken to redress the problem were given and it was reported that PTI/2 (the BSI Committee responsible for the petrol specifications) had agreed that BSI would remove the regular grade petrol specification from BS EN 228 and reissue BS EN 228: 2004. At the end of the workshop all delegates were clear as to what is required when testing petrol for RON and MON for BS EN 228: 2004 compliance.

Demountable fire protection panels for process plant equipment

In 2H2004 Aaronite Services extended its range of passive fire protection services in the manufacture and installation of demountable fire proof panels which it had pioneered in the early 1990s, for the protection of process plant equipment on offshore production installations and onshore refineries and chemical plants. The reasoning behind this development was to make available to the hydrocarbon industry a passive fire protection system that could allow the inspection of critical areas of vessels, during periods of maintenance, via easy-access panels, eliminating the need to remove in-situ fire protection and, subsequently, saving the cost of re-instatement afterwards.The fitting of demountable panels to specific sections of the vessels allows critical inspection points such as circumferential welds and liquid level lines (potential corrosion and erosion points) to be easily accessed, without the need to stop the production cycle.

The panels and support flanges are cast with a stainless steel reinforcing chassis to maintain rigidity and stability in a fire. The size of the panels are governed by the physical shape of the equipment to be protected and also the weight factor allowing 25kg/man lift limit.

Furthermore, as some plant equipment will be located in areas where access is restricted, all panels are of a size and shape that can be lifted and manipulated by hand without the need for mechanical assistance.

The system relies upon the special properties of twin component epoxy intumescent compound, which in a fire situation burns to form a carbonatious insulative char that slows down the passage of heat into the substrate of the equipment being protected.

In its normal (non fire load) unreacted state, the material is extremely durable, impact and abrasion resistant and can withstand moisture, salt spray and climatic changes – making it a fit for purpose system particularly suited to harsh offshore and refinery environments.

Standard approved fire test data from the epoxy material manufacturer is used to determine the correct thickness of material.

For quality control, all cast panels are individually marked with a unique number – not only to assist installation on site, but also to identify the master mould in the event that a replacement panel or support flange is required. In the event of an emergency, Aaronite can provide a replacement panel within a few days' notice.

Following successful blast testing on project specific demountable panels sent to Advantica at Spade Adam research test centre in Cumberland, in September 2004 Aaronite was awarded a contract to manufacture and install passive fire protection panels and support flanges for three large separator vessels on behalf of Nexen Petroleum UK for the Buzzard field development project. Over 600 panels and flanges were cast by the end of October 2004, and installed onto the vessels in Italy and Spain by the middle of December that year. All of the casting and installation work was subject to independent third-party inspection by FIRAS, Nexen Petroleum UK, John Brown Hydrocarbons and Leighs Paints.

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Pocket-sized Pageboy pump

The new Pageboy SFD15 self-priming diaphragm pump from Pump Engineering has been designed for use with aggressive or corrosive liquids.

Unlike other diaphragm pumps, which use a rod to return the diaphragm, the SFD15 uses a venturi to create a vacuum behind the diaphragm. At the end of its suction stroke, a control rod attached to the diaphragm blocks the outlet on the venturi, diverting air on to the back of the diaphragm, creating the discharge stroke. As it is used simply to separate the air from the liquid, is not subject to the same stresses as a conventional diaphragm, where the return stroke is a mechanical process. The pump will stop automatically against a closed valve, maintaining a delivery line pressure equal to the air supply pressure, and starts automatically when the delivery line pressure falls, such as when the valve is opened.

The SFD15 pump is designed for vertical upward flow and can be mounted by the extended tie rods supplied. It has a maximum output of 3 litres/min and maximum pressure of 6 bar.

t: +44 (0)1903 730900
www.pumpeng.co.uk

Top grades in petrochemical training

AOC Commercials, the Carrigtwohill-based Scania dealer, has received full pass marks for five of its fitters and engineering staff following a recent TransTrain petrochemical safety and procedures course held at Glenroyal Hotel, in County Kildare. The TransTrain course, which covers all aspects of safety, maintenance, testing and general procedures concerning petroleum road tankers, lasts three days and ensures that operatives at every level of involvement with petrochemicals do not put themselves, their company or others at risk.

Explaining why he had opted for TransTrain safety training, AOC Commercials Managing Director Pat Curtin said: 'Although, of course, it is potentially serious, this is not just about accident prevention and reducing risk. Just as important is to ensure that our customers are provided with a maintenance, back-up and repair service of the very highest standard. Safety is paramount in everything we do. These industry-recognised TransTrain courses not only ensure that essential procedures are followed, but also that workmanship, quality and up-time remain consistently high.'

Each of the successful candidates from AOC will receive a certificate endorsed by the SOE and the Energy Institute and will be placed on a national register noting their qualification.

Commenting on the results, TransTrain Trainer and Director George Fox — who himself has worked in the front line of petrochemical distribution for over 30 years – said: 'These three-day courses, which run throughout the year, serve to bolster the knowledge and capability of all those involved at the sharp end of the petrochemical transport business. We also provide a less intensive one-day course for those people who wish to gain a basic understanding of the safety, general handling and emergency response procedures relevant to the business. I am delighted with the level of attainment demonstrated by AOC and am confident that both they and their customers in turn will benefit from the course.

There are a limited number of places still available during 2004 to be held at the Kingsbury BP Oil Terminal, West Midlands. Anyone interested in attending should call Jane Brown on:

t: + 44 (0)1326 569267
f: +44 (0)1326 565847

Wireline tractor designed for open hole operations

Statoil and Maritime Well Service have signed a technology agreement for development of a new wireline tractor for use in oil and gas wells without casing. Statoil aims to save between NKr2mn and NKr2.5mn for every well operation of this nature through use of the new technology.

The existing wireline tractor technology from Maritime Well Service uses hydraulically driven wheels to provide propulsion and is mainly used for the conveyance of tools in horizontal wells for acquisition of production data, and for plug setting and perforating operations.

The new tractor will be for use in open hole wells, which have no wall casing or lining. To operate a wireline tractor in such wells, a new type of propulsion mechanism based on chain tracks will be developed. Initial tests of the prototype have been successful and both Statoil and Maritime Well Service aim to have the technology available for operation in 3Q2005.

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Fair Shares and Romanian Oil*

Ronald Atkins (The Book Guild, Temple House, 25 High Street, Lewes, East Sussex BN7 2LU, UK. t: +44 (0)1273 472534; f: +44 (0)1273 476472; e: **info@bookguild.co.uk***;* **www.bookguild.co.uk***). ISBN 1 85776 864 7. 232 pages. Price: £16.95 (hardback).*

Ronald Atkins' aunt Vera was a famous figure in the Special Forces Executive. Her heroism during World War II made the author realise that he knew nothing about her brother, his mysterious father – so he started a quest to discover more. How did anyone from Sussex get to Istanbul on the Orient Express in the 1940s? What exactly was his father doing there? How and why did a suitcase full of white £5 notes arrive at an opportune moment during Ronald's childhood? Plotting his father's intriguing progress through the war, the author manages to highlight some of the relatively unknown chicaneries of the British Government and its sending of officials into the Romanian oil companies.

Inverse and Risking Methods in Hydrocarbon Exploration*

Ian Lerche (Multi-Science Publishing, 5 Wates Way, Brentwood, Essex CM15 9TB, UK. t: +44 (0)1277 224632; f: +44 (0)1277 223453; e: **mscience@globalnet.co.uk***;* **www.multi-science.co.uk***). ISBN 0 906522 32 3. 502 pages. Price: £58.*

This book looks at how modern developments have enhanced the utility of basin analysis in hydrocarbon exploration. A major factor is modern computing power, which enables complex Monte Carlo-type calculations to be rapidly carried out; a second is the transfer of concepts from the economic arena to the theatre of hydrocarbon production, for example setting risking procedures to cope with data uncertainties. In addition, there are now available powerful methods for handling the determination of parameters in the highly non-linear world of equations describing various facets of basin analysis. These methods include genetic algorithms, simulated annealing methods and the so-called 'fast path' method. All these novel procedures and methods are brought together in this volume so that students, as well as professionals, can see what the recent developments in basin analysis have amounted to, and so invoke the procedures as a solid, stable platform to build on.

Method for Monitoring Exposure to LPG Containing Small Amounts of 1,3-Butadiene*

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

This report describes the validation of a sampling and analytical methodology for occupational exposure monitoring of LPG and its components, including trace amounts of 1,3-butadiene – classified as a carcinogen.

Working at Height (video)

(IMCA, 5 Lower Belgrave Street, London, SW1W 0NR, UK. t: +44 (0)20 7824 5520, f: +44 (0)7824 5521; e: **imca@imca-int.com***;* **www.imca-int.com***). Price: IMCA members – £10 + VAT; non-IMCA members – £50 + VAT.*

The offshore oil and gas sector is an industry leader in developing safety practices and safe working systems. However, falls from heights remain the single largest cause of death and serious injury in industry today. The International Marine Contractors Association (IMCA) has produced this video (in English, with subtitles in Arabic, Filipino, French, Indonesian Bahasa, Italian, Malay, Portuguese and Spanish) to help promote the need for safety awareness when working at height – taking the time to use proper protective equipment, safe working practices and looking out for yourself and your colleagues.

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Photo: Jim Four

The EI Awards ceremony will take place on Friday 25 November 2005 at the Savoy Hotel, Strand, London.

To book a table at the ceremony please contact Arabella Dick, t: +44 (0)20 7467 7106,
e: arabella@energyinst.org.uk

Guest speaker and presenter 2005
Sir Ranulph Fiennes Bt OBE

A big thank you to all who submitted projects for EI Awards 2005. We will be in touch shortly.

The deadline is now closed.

For sponsorship opportunities, please contact Marta Kozlowska, EI Business Development Manager, t: +44 (0) 20 7467 7104
e: marta@energyinst.org.uk

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