AUGUST 2005

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: Vopak's oil storage facilities in Rotterdam *Photo: Vopak*

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FROM THE EDITOR

Just another turbulent month

One of the great pleasures of writing about the oil and gas industry is that it is endlessly fascinating. A dull month is almost a contradiction in terms and the last month has had more than its fair share of drama and excitement.

The month started very positively, with Lehman Brothers' mid-year update of its E&P spending survey. The original December 2004 report foresaw increased worldwide E&P expenditure of 5.7% in 2005 by the 356 companies in the survey. The mid-year revision now anticipates a 13.4% increase to $192bn in 2005.

Clearly, tight supply and high prices are now beginning to trigger increased expenditures. However, high steel costs, specific labour shortages, capacity constraints in key supply areas and rising energy costs are all inflating project costs.

It is not at all clear that even the higher expenditures will result in real increases in activity. Shell's major asset swap – where Gazprom took 25% of the Sakhalin II project in exchange for Shell taking 50% of the deeper producing horizon in the Zapolyarnoye gas field in Yamal-Nenets – appeared a triumph until new cost figures for Sakhalin II were announced. The latest estimate for this key project is now $20bn, where just two years earlier it had been $10bn. There are undoubtedly special features and difficulties in undertaking a major project in Russia, but much of the cost inflation is that faced by every other large oil and gas project.

BP appears to be involved in something of a cliff-hanging drama, with the ballasting problem/accident on the Thunder Horse production platform. Even if the cause proves straightforward and fixable, delays to the project start-up appear to be inevitable as official enquiries/surveys/certifications grind through due process.

BP's minority partner in Thunder Horse – ExxonMobil – can be forgiven a certain pride that the Kizomba B project started up early, in July. Kizomba B is one of a select few major projects to have genuinely started up early. Company PR departments love to put out early start-up announcements – however, these are invariably only early on the revised, revised schedule. Kizomba B is exceptional in being early even against the earliest schedule. Something of a triumph for Exxon's standardisation under its 'design one, build several' philosophy.

Michel Contie, in his Cadman Lecture speech (p32), reminded us that people still have a lot of fun working in the oil industry, while also noting how the challenges are getting tougher.

One of the industry's major challenges is to replace the production lost to capacity erosion each year. [*Petroleum Review* now intends to use the term 'capacity erosion' rather than 'depletion' simply because the latter seems to provoke irrational and emotional responses as well as implying the cause is physical rather than financial.]

Our analysis of the latest BP statistics (see p43) shows that, although the number of countries, where capacity erosion is leading to a reduction in volumes produced, has increased from 18 to 20, the overall volume of production lost to capacity erosion actually fell by 200,000–300,000 b/d in 2005. Clearly, incremental investment is now slowing capacity erosion. The analysis has been greatly complicated by the size and extent of recent data revisions in the *BP Statistical Review*. North Sea production data also seems to be the subject of larger than usual data revision. Hopefully this will lead to more accurate data to work with.

Our reviews of the US and Canada (p17 and p20) show some of the ambitious plans to expand Gulf of Mexico production and Canadian tar sands output. They also hint that future gas supplies remain a concern and a constraint. The Mackenzie Delta pipeline has yet to get the go-ahead, while the Alaska pipeline appears as far away as ever. More encouragingly, LNG import terminals in the US and Canada are now under construction.

On the oil front, although prices remain very firm, spiking above $60/b on any negative news, the supply situation appears reasonably well balanced. According to the latest International Energy Agency (IEA) report, stocks are starting to build, Opec is maintaining high levels of output and new projects are coming onstream more or less on time. However, the '900-lb gorilla in the corner of the room' is what happens in the fourth quarter when, according to the IEA, demand hits 85.9mn b/d – up from 81.9mn b/d in the second quarter and 83.7mn b/d in the third quarter.

However, if oil supply is going to be challenging later this year, then so is gas. The BP statistics tell us that in 2004 US production fell by 1.2%, while demand rose by 0.2%. In Canada, production was flat and demand declined by 2.9%. This effectively let the US off the hook, with Canada and LNG making up the US shortfall. This year looks more challenging, with the forward gas price already over $9/mn Btu for the winter quarter, which, in turn, is producing forward electricity prices up to 50% above recent levels.

In Europe the outlook is even more challenging. Gas production in 2004 fell in Germany (–7.5%), Italy (–5.5%) and the UK (–6.7%), but demand grew by 0.4%, 3.8% and 2.7% respectively. UK forward gas prices are escalating dramatically, as are forward electricity prices. This summer's drought is likely to restrict hydro generation and may lead to shortfalls in French nuclear generation or low river levels. Supplying gas and electricity in Europe is going to be very profitable this year. Customers may see it differently.

Chris Skrebowski

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

E-DATA

Chevron has launched a new global advertising campaign to raise awareness and encourage discussion about important issues facing the energy industry, including supply and demand, the role of alternative and renewable energy sources and the promise of technology. The campaign will include print and broadcast in major media, and an innovative website – **www.willyoujoinus.com**

Big Oil Associates, which provides online intelligence on the critical fuel price market, has secured a £170,000 funding package to develop the range of its Internet-based services for the petroleum industry. The website **www.BigOil.net** provides daily critical fuel price market intelligence on an annual subscription basis. It had been developed initially for the independent fuel retailer, but now also caters for commercial distributors and commercial end users such as haulage, coach and construction companies.

Island Oil and Gas has launched a new website at **www.islandoilandgas.com** that includes up-to-date information on the company and its projects, as well as share price and other investor tools.

Due to an increasing interest in Statoil among the authorities, companies and media in Russia, the company has launched information in Russian on the group's website at **www.statoil.com** These pages include information about the Statoil organisation and its business operations in Norway and internationally.

UKPIA, the trade association representing the main oil refining and marketing companies in the UK, has published its *2005 Statistical Review* of the downstream oil industry at **www.ukpia.com** under 'Publications'.

UK

BP has reported that 2Q2005 oil and *gas production growth slowed to 3.5% amid higher taxes and restrictions on exports in Russia. Second-quarter production increased to 4.11mn b/d, compared with 3.97mn b/d in 2Q2004. Total production for 2005 is forecast to be between 4.1mn and 4.2mn b/d – an increase of between 2.6% and 5.1% this year.*

Paladin Resources (operator, 58.97%) *has reported that the North Sea Brechin oil field has come onstream at an initial rate in excess of 8,000 b/d.*

EUROPE

A letter of intent has been signed by *Statoil with Kongsberg FMC for the delivery of a subsea separation station to improve oil recovery on the Tordis field in the North Sea from 49% to 55%.*

A NKr160mn contract for laying the *Tampen Link pipeline in the North Sea has been awarded by operator Statoil to Saipem UK. Tampen Link is scheduled to be ready for operation on 1 October 2007, when the operatorship will be transferred from Statoil to Gassco. The pipeline will carry gas produced by the Statfjord late life project.*

Norsk Hydro reports that the satellite *subsea J-structure at the Oseberg South field in the North Sea has been put into operation. Recoverable reserves are put at 24mn barrels of oil and 500mn cm of natural gas.*

Shell has agreed plans with Aker *Kvaerner to reuse the Brent anchor*

World drilling first for Statoil

Statoil reports that it recently completed what it claims is the world's longest well drilled from a floating installation, on its Visund field in the Norwegian North Sea. Also ranked as the longest well so far drilled by the group, the A-6 producer reached a total measured length of 9,082 metres. The Visund operation was carried out in cooperation with Odfjell Drilling and Schlumberger, which served as the directional drilling company. Work on the Visund gas project means that the A-6 producer will not come onstream until October. Its potential is seen as very high as it penetrates 800 metres of hydrocarbon sands.

PNG gas deal

AGL of Australia is understood to have agreed a deal under which it will take \$4.5bn worth of Papua New Guinea (PNG) gas – some 1,500 PJ – over the next 20 years to supply residential and industrial customers from Townsville to Melbourne.

AGL will also take a 10% stake in the A\$3bn (\$4.04bn) PNG phase of the project, which involves building a gas processing plant and a pipeline from the rugged Southern Highlands of PNG across the Torres Strait to Cape York. AGL will also lead a consortium to build a \$2.5bn pipeline system linking Cape York to customers in Queensland and the Northern Territory and, later, Sydney and Melbourne.

It is hoped that the long-awaited PNG gas project will help reduce the country's dependence on foreign aid. Aid from Australia accounts for 30% of the PNG budget.

Sakhalin II project cost estimates

Sakhalin Energy Investment Company (SEIC) provisionally anticipates that Phase 2 project investment costs for the Sakhalin II project could be of the order of \$20bn, covering all planned development activity including drilling activity through to 2014, with LNG deliveries starting in the summer of 2008.

The estimates are still 'work in progress' and remain subject to shareholder review and confirmation.

SEIC currently has over 75% of its LNG capacity sold under long-term contracts and is in negotiation with buyers for the balance of production capacity.

Recoverable reserves are put at 17.3tn cf of gas and 1bn barrels of oil, which, at SEIC's indicated revised estimates, means a project development cost of some \$5 to \$6/boe and includes the LNG plant.

New North Sea deals for Dana

Dana Petroleum has agreed a farm-in with Shell UK and Esso Exploration & Production UK, under which it will drill a well in an area of UK North Sea block 23/16b into which the Barbara gas-condensate discovery is mapped to extend. The well will appraise the extent of the original discovery made by Dana and its co-venturers with the 23/16c-8 exploration well in the neighbouring block. In return for drilling the well, Dana will be assigned a 50% interest in, and operatorship of, the Barbara extension-area within block 23/16b.

In addition, Dana has agreed a two-for-one farm-out to Endeavour Energy UK, whereby Endeavour will fund 40% of the cost of an exploration well to test the Fiacre prospect in UK North Sea block 23/11, which lies directly to the north-east of the Barbara field. In return, Endeavour will be assigned a 20% interest in the Fiacre sub-area of block 23/11, which specifically excludes the mapped extension of the Barbara field into 23/11. Dana will therefore pay 40% of the Fiacre well cost whilst retaining a 60% interest in, and operatorship of, the block.

Under the terms of the agreement with Endeavour, Dana has also been granted the reciprocal right, effective until the end of 2006, to participate on a similar 'two-for-one' basis for up to a 20% working interest in Dana's choice of up to two UK North Sea exploration or appraisal wells in which Endeavour has an interest.

Both the forthcoming Barbara appraisal and Fiacre exploration wells will be drilled as part of Dana's 2005 North Sea operated programme. The *Bredford Dolphin* semi-submersible drilling rig has been contracted for this work with the Barbara appraisal well expected to start as *Petroleum Review* went to press. This will be followed by the Fiacre exploration well and subsequently, the Clachnaben exploration well in block 211/22a.

A further exploration well has also been approved in the Netherlands sector of the North Sea, to test the E18a-DF prospect. This well will follow completion of the adjacent F16-E gas field development, which is now due onstream in October 2005.

blocks in a land reclamation scheme. The blocks will be used for foundations of a demarcation and a retaining wall for an alternative set down area at the Aker Stord decommissioning yard.

Hydro has submitted a plan for development and operation of the Oseberg Delta satellite field in the North Sea. Production start is scheduled for October 2007.

NORTH AMERICA

Rosetta Resources, a newly formed US independent, is reported to have completed the purchase of all of the domestic oil and gas E&P assets formerly owned by Calpine Corporation for $1.05bn.

Unocal is to sell all of the outstanding stock of its wholly owned Canadian subsidiary, Northrock Resources, to Pogo Producing Company for $1.8bn in cash.

Spinnaker Exploration (50%) has announced that its Q discovery in Gulf of Mexico Mississippi Canyon block 961 has been confirmed via an up-dip sidetrack of the discovery well. Q is to be produced through the Independence Hub production facility that is scheduled for first production in 2007.

Kerr-McGee has announced a deepwater Gulf of Mexico discovery at East Breaks 599. The field has potential resources in the range of 10mn to 20mn boe and will be developed as a subsea tie-back to the Kerr-McGee-operated Boomvang production hub.

MIDDLE EAST

Foster Wheeler has been awarded a front-end engineering (FEED) and project management services contract by Saudi Aramco for the Khurais full-field development in Saudi Arabia. The field is forecast to produce 1.2mn b/d of Arabian light crude by 2009.

RUSSIA/CENTRAL ASIA

Rosneft and KazMunaiGas are planning to invest $23bn in a 55-year production sharing agreement for the Kurmangazy oil field in the Caspian Sea. Recoverable oil reserves at Kurmangazy are put at 980mn tonnes.

Gazprom and Shell have signed a memorandum of understanding (MoU) under which Gazprom would acquire up to

Caspian platform sets sail

The Azerbaijan International Oil Company's (AIOC) compression, water injection and power (CWP) topsides recently set sail for its new home after 18-months of construction at the AMEC-Tekfen-Azfen (ATA) consortium's facility in Baku. The 14,500-tonne CWP platform will provide support to three oil production platforms that form part of the Azeri-Chirag-Gunashli (ACG) development operated by BP on behalf of AIOC in the Azeri sector of the Caspian Sea.

The platform will be connected by a bridge link to the Central Azeri drilling and quarters platform. It will also provide electrical power via subsea power cables to the two production platforms in West and East Azeri.

Russian field development agreement

Rosneft and Novatech have signed a long-term cooperation agreement for development of the Kynsko-Chaselsky group of fields and the Termokarstovsky deposit, all located in the Krasnoselkupsky district of the Yamal-Nenets Autonomous District, Russia. In addition, Rosneft has acquired Novotech's 34% stake in Selkupneftegaz, giving Rosneft full control of the company.

Recoverable reserves at the Kynsko-Chaselsky group of fields are put at 10.4mn tonnes of oil, 13mn tonnes of condensate and 103bn cm of gas. The Kynsky field – the first stage of development of the Kynsko-Chaselsky group of oil fields – came onstream in March 2003. Rosneft subsidiary Purneftegas plans to initiate development of five more fields belonging to the group – Fakhirovsky, Novochaselsky, Ust-Chaselsky, Verkhne-Chaselsky and Naumovsky – over the next few years. The Termokarstovsky field holds some 47.3bn cm of gas and 10mn tonnes of liquid hydrocarbons.

Neptune development a step closer

The Neptune consortium – formed by Maxus (US) Exploration (15%), BHP Billiton (designated operator, 35%), Marathon Oil (30%) and Woodside Energy (20%) – has approved capital expenditure to develop the Neptune oil and gas field in the deepwater Gulf of Mexico. The Neptune facility will have a design capacity to produce up to 50,000 b/d of oil and 50mn cf/d of gas, with gross costs for the development estimated at some $850mn.

The Neptune field comprises Atwater blocks 573, 574, 575, 617 and 618. Recoverable reserves are put at between 100mn and 150mn boe. A standalone, tension leg platform (TLP) has been selected for the development. First oil is expected by the end of 2007, with seven initial subsea wells tying back to the TLP. Oil and gas will be exported to shore via the existing Caesar and Cleopatra trunk lines.

Transboundary North Sea field projects

Plans for the first North Sea oil fields to be developed since a new UK-Norway transboundary agreement was signed in April 2005 to fast-track developments across national boundaries have been approved by the UK and Norwegian governments. Enoch and Blane, operated by Paladin Resources, are expected to begin production by the end of 2006, initially producing some 26,000 b/d.

The Enoch field will be tied-back to Marathon's Brae platform for processing and the onward transportation of the oil via the Forties pipeline system. Blane will be developed via a subsea drilling template and production manifold on the UKCS tied back to the Ula platform on the Norwegian Continental Shelf. Gas from Blane will be reinjected at the Ula reservoir to provide pressure support, while the oil will be transported to Teesside via the Norpipe system.

25% plus one share in the Sakhalin II venture, and Shell would acquire a 50% stake in the Zapolyarnoye-Neocomian field in western Siberia. The difference in value, to be defined by the parties, will be compensated through a package of cash and other assets to be agreed by the parties.

***Lukoil and ConocoPhillips have established** a joint venture – Naryanmarneftegaz – to develop resources in the northwest Arctic region of Russia.*

***The Alexandrovskoye field in the** southern Perm region – operated by Ural-Oil, a Lukoil subsidiary – has come onstream, producing 12 t/d of oil from two wells. Proved reserves are put at about 1mn tonnes of oil.*

***Total has signed a memorandum of** understanding (MoU) with Gazprom for the development of the giant Shtokman gas field in the Barents Sea.*

ASIA-PACIFIC

***Aker Kvaerner has been awarded a** contract by Murphy Sabah Oil for the engineering, procurement, construction and commissioning assistance of the subsea production systems for the Kikeh project in Malaysia – the first deepwater development of its kind in the Asia-Pacific.*

***Shell Development Australia (Shell) has** been awarded exploration rights to four deepwater blocks in the Carnarvon basin offshore Western Australia, in which Shell will have a 50% interest. Chevron will be the operator of all four permits.*

***India's state-owned Oil and Natural** Gas Corporation (ONGC) is reported to have made a significant gas find in the shallow waters of the Krishna Godavari basin off the Andhra Pradesh coast. The find was made on the GS-15 prospect, south-west of the Ravva field.*

***The East Timorese Parliament is under**stood to have unanimously passed the first of three laws – the Petroleum Fund Act – that will pave the way for exploration in the country's undisputed maritime region. The Act will ensure that all revenues and all payments received from petroleum exploration are paid into a fund that will be managed and supervised in a 'transparent and accountable way'.*

***The Greater Gorgon joint venture part**ners – Chevron (50%), Shell (25%) and ExxonMobil (25%) – have awarded front-end engineering and design*

UK oil output decline continues

UK oil production in April fell by 11% compared to March levels, to reach 1,749,773 b/d, continuing the past year's trend of declining production, according to the latest (July) Royal Bank of Scotland *Oil and Gas Index*. Gas production was also down by 16% on the year, at 10,290mn cf/d.

Tony Wood, Senior Economist with The Royal Bank of Scotland Group, said: 'The ongoing rate of decline of UK oil and gas production continues to be of concern. However, high oil prices combined with the success of the recent Seaward Licensing Round point to a much more positive operating environment in the UK for at least the next two years.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Apr 2004	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	8,716	42.92
Oct	1,630,230	9,677	49.66
Nov	1,748,744	10,385	42.88
Dec	1,800,309	10,823	39.55
Jan 2005	1,725,929	10,444	44.24
Feb	1,742,295	9,759	45.50
Mar	1,703,744	10,514	52.95
Apr	1,749,773	10,290	51.83

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Kearl oil sands project proposal put forward

Imperial Oil has filed regulatory applications for development of the Kearl oil sands project with the Alberta Energy and Utilities Board and Alberta Environment. Imperial is the designated operator of the proposed joint-venture project, which would be located on portions of oil sands leases held by Imperial and ExxonMobil in the Kearl Lake area of the Athabasca oil sands deposit.

The project would be similar in design to existing oil sands mines in the Fort McMurray region, using large-scale shovels, trucks, crushers and oil sands hydrotransport technology.

The current plan is to develop the mine in a staged manner, with an initial mine train with production capacity of about 100,000 b/d. Subsequent expansions could increase capacity to approximately 300,000 b/d. The mine application does not include any on-site bitumen upgrading. Any future upgrading capacity to support the Kearl project would be the subject of a separate application.

First production could be by the end of 2010, with two further mine trains starting up in 2012 and 2018. Total recoverable bitumen resources on the leases are estimated at 4.4bn barrels.

Petro-Canada's Pict field onstream

Petro-Canada's Pict development, which is located in block 21/23b in the central North Sea, achieved first oil on 19 June 2005. Reserves are put at 15mn barrels.

The field, which had lain fallow for nearly two decades, has been developed with subsea facilities tied back to the Triton floating, production, storage and offloading vessel (FPSO) via the Guillemot West and Northwest infrastructure.

Pict is expected to produce an average of 10,000 boe/d over the next three years. Petro-Canada's next UK development to come onstream will be the Buzzard field, in which it has a 29.9% interest. First oil is due at the end of 2006 and plateau production of about 60,000 boe/d net to Petro-Canada is expected in late 2007.

(FEED) contracts to a consortium comprising Kellogg, JP Kenny and Technip. The FEED scope for the Greater Gorgon development includes the establishment of a two-train (10mn t/y) LNG facility and domestic gas plant on Barrow Island, supplied by gas fields in the Greater Gorgon area. First gas is expected in 2010.

Pogo Producing Company has entered *into a definitive agreement to sell its Thailand assets to PTTEP Offshore Investment Company and Mitsui Oil Exploration for $820mn in cash.*

LATIN AMERICA

Total reports that the Carina-Aries gas *fields located offshore Tierra del Fuego, Argentina, have been brought onstream. Output will eventually ramp up to a plateau of 8mn cm/d.*

UK independent Venture Production is *to sell in a cash ($11mn) and stock deal its Trinidad operations to Ten Degrees North Energy (TDN), a new Trinidadian company that was recently formed by Dr Jim Lee-Young (previously Venture's General Manager in Trinidad) and Bruce Dingwall (who was a founder and former Chief Executive of Venture). Venture will retain an interest in the assets through a 40% equity stake in TDN.*

AFRICA

Egypt anticipates $20bn investment in *its oil and gas industry over the next five years as part of policies to boost economic sectors, writes* Stella Zenkovich. *Oil Minister Sameh Fehmi said the Cairo government expects foreign investments worth $16bn in the oil and gas industries, in addition to $4bn in local investments – divided equally between public and private sectors. The Egyptian Oil Ministry is expected to sign 39 agreements with foreign oil companies this year, covering E&P and the development of existing fields.*

The NNPC *(National Nigerian Petroleum Company) is reported to have announced that a further 14 blocks have been added to the 60 blocks recently put up for bidding. The listed blocks are intended to encourage investors to develop power plant and LNG projects in Nigeria, with a number of the blocks offered as part of a deal for the Kaduna refinery privatisation – a project in which a Chinese consortium has shown interest.*

Global oil and gas risks and rewards

A recently published report entitled *Global Oil and Gas Risks and Rewards (GOGRR)* by global energy consultant Wood Mackenzie compares exploration performance and returns for international oil companies (IOCs) in 66 areas across 58 countries between 1994 and 2003. Using Wood Mackenzie proprietary data and commercial models specific to given fields and areas, the independent study assesses the value created by exploration over the last 10 years.

'In absolute terms, the biggest successes include Kazakhstan and the deepwater areas in the Gulf of Mexico, Angola and Nigeria,' explains Graham Kellas, VP Petroleum Economics for Wood Mackenzie. 'Kazakhstan ranks number one in terms of commercial reserves discovered, average discovery size, reserves discovered per well and finding costs per boe. The world class Kashagan find in 2000 is the major factor, however. Kazakhstan has been enjoying considerable success since, including the discovery of two other "giant" fields in 2003.'

The US Gulf of Mexico (deepwater) ranks number one for absolute value created and second for commercial reserves discovered. Both Angola and Nigeria recorded commercial success rates greater than 25% and score highly in terms of reserves discovered.

'On relative measures such as full cycle IRR (internal rate of return) and value created per boe discovered, there are some interesting results – the Netherlands ranks first on both criteria for example,' continues Kellas. 'This may appear surprising at first, given that it is an area viewed as mature with limited upside. High commercial success rates, low exploration costs and relatively lenient fiscal terms, however, combine to drive attractive risked economics. In fact, a low government take was found to be the most significant driver for generating high value per boe discovered.'

According to Wood Mackenzie's study the biggest disappointments include deepwater Brazil and Azerbaijan. 'Although originally hoped by IOCs as being the new hot play, deepwater Brazil has been a big disappointment,' Kellas explained. 'No commercial discoveries have yet been made by IOCs, despite having spent nearly $1.5bn in exploration and appraisal drilling and signature bonuses.'

Azerbaijan, despite having the largest average gas discovery size per well, ranks second lowest in terms of value created. The Shakh Deniz field has driven the reserve metrics, but low gas prices, low success rates and high costs have negatively impacted value creation.

Two-thirds of the countries examined in the study have created value and there is no doubt that the cushion of recent (and anticipated future) high oil prices enhances the exploration performance in many countries. Indeed, if future prices remain in the mid-$30s then value creation from existing commercial discoveries could rise to over $220bn.

Between 1994 and 2003, IOCs were tremendously successful in finding commercially recoverable oil and gas around the world. On top of this, a further 17.6bn barrels of liquids and 217tn cf of gas were discovered in the period, which, for a variety of reasons, are not currently deemed commercial. Many of these discoveries will eventually be developed and brought to market, and with many companies planning significantly increased exploration drilling plans this year, hopes are that there will be many more to come.

Oil and gas will continue to dominate in UK

The UK will become increasingly reliant on oil and gas to meet its primary energy needs over the next 10 to 15 years, despite efforts to promote energy from renewable sources, according to the UK Offshore Operators Association (UKOOA) recently published annual economic report. UKOOA Chief Executive Malcolm Webb said: 'The government's projections show that the UK's oil and gas needs will rise from the current 74% of primary energy to 85% in 2020, with demand for gas for power generation growing by around 60% over the same period.'

He continued: 'If we don't produce oil and gas ourselves then we will have to import it. If the UK had to import all its oil and gas, in 2005 alone our import bill would be around £30bn higher, increasing the current UK trade deficit by almost 75%, and UK tax revenues from oil and gas would be about £10bn lower because imported oil and gas pays no UK corporation or petroleum revenue tax. It makes sense, therefore, from the economic, as well as the security of supply, viewpoint to do all we can to maximise the recovery of our own oil and gas reserves. This will require careful nurturing of the right business environment – one which is conducive to investment, not impaired by the cost of inappropriate regulation and not thrown off balance by unexpected fiscal changes.'

The report is available at www.oilandgas.org.uk/issues/economic/index.htm

UK

***BP is to retain Chairman Peter** Sutherland for at least a further three years until a successor has been found for Lord Browne, its long-serving Chief Executive.*

***The first commercial cargo of LNG to** arrive at the UK for more than a decade unloaded on 4 July. The* Berge Arzew, *carrying 30mn therms of Algerian gas, unloaded at the new £130mn LNG National Grid Transco terminal at Isle of Grain in Kent.*

***IHS Energy is to market a global biodi**versity information module to the energy industry. For more details, visit* **www.ihsenergy.com/products/biodiversity**

***The UK government has published its** latest* Energy Trends *and* Quarterly Energy Prices *bulletins, which can be viewed at* **www.dti.gov.uk/energy/inform/energy_stats_overview/index.shtml**

EUROPE

***Esso Nederland and Shell Nederland** have formally transferred their 25% stakes in Gasunie's gas transportation business to the Netherlands' government. In return, the government has paid 2.77bn to NAM, the Dutch oil and gas producing company jointly owned by ExxonMobil and Shell.*

***Finland is reportedly planning to** import gas from Latvia via a pipeline under the Baltic Sea from Estonia, which could be operational by 2010.*

***Up to 22% of GdF is to be offered to** private investors in a sale that is opposed by France's energy unions.*

***France has been selected as the site of** what is claimed to be the world's first nuclear fusion reactor – the International Thermonuclear Experimental Reactor (ITER). A six-member consortium, which includes the US, Russia, China, Japan, South Korea and the European Union, will build the ITER at Cadarache in southern France.*

***The Boards of Royal Dutch, Shell** Transport and Royal Dutch Shell have reported that the implementation agreement for the proposed unification of Royal Dutch and Shell Transport under a single parent company has been approved by an overwhelming majority of the Royal Dutch shareholders at the recent AGM.*

Wingas' new gas entry-exit system

In order to facilitate further access to its gas transmission network, Wingas (65% Wintershall, 35% Gazprom) introduced an entry-exit system on 1 July 2005. The system has been designed to 'ensure transparency and minimum effort for contractual transactions'. It includes just four sub-grids. Capacities for the delivery and redelivery of gas can be booked flexibly and independently for each sub-grid at different levels, at different times and for different periods.

Wingas will charge all of its transmission customers throughout Germany a uniform entry and uniform exit tariff on all of the sub-grids – regardless of the actual location of the gas entry or exit point in each respective sub-grid.

To further simplify the gas supply to consumers with fluctuating energy consumptions, several transmission customers can form balancing pools, in which differences in quantities fed in at the entry points and quantities taken off at the exit points can be balanced.

In addition, Wingas is offering the option of completely dispensing with 'manual' nominations in its system and automatically allowing the gas consumption of the end customer to apply as the nomination at the entry point. This 'nomination with time delay' prevents the occurrence of large quantity differences right at the outset, explains the company.

With the corresponding booking, balancing pools can also encompass more than one sub-grid. In these sub-grids transmission customers can pass on gas to third parties via virtual trading pools. The sale of network capacities that become available is possible via secondary marketing. 'In this way, gas traders also obtain important instruments to permit a reliable and flexible supply of gas to end users,' comments Wingas.

EnCana to divest gas storage business

EnCana is to divest its natural gas storage business, either through a competitive auction process or an initial public offering. The business is North America's largest independent gas storage network, with assets located in key gas producing and consuming regions and linked to intercontinental pipelines.

EnCana Gas Storage has approximately 174bn cf of working gas capacity at five facilities in Alberta, California and Oklahoma. The AECO Hub™ in Alberta is comprised of three facilities totalling 135bn cf of storage capacity. Wild Goose Gas Storage in northern California has 24bn cf of storage capacity, while Salt Plains Gas Storage in Oklahoma has 15bn cf of storage capacity. EnCana is also developing a new gas storage project, Starks Gas Storage, in south-west Louisiana.

EnCana will retain ownership of its Hythe storage facility, which has 10bn cf of storage capacity, and may enter into other commercial storage arrangements with the new owner of the divested assets.

BG Energy Challenge raises £220,000

The tenth BG Group Energy Challenge raised a record-breaking £220,000 for aid agency CARE International's overseas work in the poorest communities around the world – including Chad, Angola and Brazil, whose economies are dependent upon revenue from the oil and gas sector.

The event is designed exclusively for teams working in the oil and gas industry, who are challenged with climbing three mystery mountains and completing a mystery activity – all within 24 hours.

This year's tenth anniversary event took place in the Scottish Highlands and the Lake District, and involved 26 teams recruited from 19 companies, including BP, Transco, BHP Billiton, ConocoPhillips, Sealion Shipping, Clariant Oil Services, among others.

Egyptian LNG train two financing agreed

BG Group, along with its partners, has signed the financing documentation associated with the $880mn project financing for Egyptian LNG train two. The total amount of debt raised represents the second largest ever project financing in Egypt after that of Egyptian LNG train one, states the company.

The partners in Egyptian LNG train two include BG Group (38%), Petronas (38%), the Egyptian Natural Gas Holding Company (12%) and the Egyptian General Petroleum Corporation (12%). Egyptian LNG train two is due to produce its first LNG cargo before the end of 2005. The BG-operated Sapphire field in the West Delta Deep Marine Concession, which is due to produce first gas in 3Q2005, will supply gas to train two. The entire 3.6mn t/y output has been sold to BG Gas Marketing.

ConocoPhillips and Essent Energie *have signed a memorandum of understanding (MoU) to study the feasibility of developing an LNG import terminal at the port of Eemshaven in the Netherlands.*

NORTH AMERICA

ConocoPhillips has completed restructuring *its ownership of Duke Energy Field Services after it increased its ownership in DEFS from 30.3% to 50% in exchange for a combination of assets and cash valued at $1.1bn.*

Woodside Petroleum has pulled out of *the Clearwater Port LNG receiving terminal project offshore California and is now considering development of its own site nearby.*

China's largest offshore oil and gas *producer CNOOC has signalled a takeover battle with Chevron by offering a $18.5bn all-cash bid for Unocal. If successful, CNOOC's bid will be the largest-ever overseas acquisition by a Chinese firm.*

MIDDLE EAST

Iran is understood to have signed an *agreement to export 10mn t/y of LNG to China from 2009. No further details are available.*

RUSSIA/CENTRAL ASIA

Gazprom plans to start building its *North European pipeline by the end of 2005, having decided on forming a unit called Gazpromzapadinvest to lead the construction project, writes* Stella Zenkovich. *The pipeline will take gas to Germany across the Baltic from Vyborg, a port near St Petersburg and the Finnish border. Spurs from the main pipeline could also feed gas networks in Finland, Sweden and the UK.*

Gazprom is planning to stop subsi*dising the oil it supplies to the countries of the Former Soviet Union (FSU) and, from 2006, charge market prices instead.*

ASIA-PACIFIC

Malaysia LNG Tiga, a subsidiary of *Petronas, is to supply Korea Gas Corporation (Kogas) with up to 2mn t/y of LNG for 20 years, beginning 2008, with an option to extend for another five years.*

Petronas expands gas sales to Japan

Petronas subsidiary Malaysia LNG (MLNG) has signed a sale and purchase agreement (SPA) with Hiroshima Gas to supply up to 82,000 tonnes of LNG to the Japanese company for eight years, beginning in 2H2005. The deal increases MLNG's customer base among the Japanese power and gas companies to 12.

The LNG will be supplied from the Petronas LNG complex in Bintulu, Sarawak, and will be delivered to Hiroshima Gas' receiving terminal at Hatsukaichi in Japan on ex-ship basis. Hiroshima Gas is the seventh largest city gas company in Japan in terms of gas sales, supplying primarily to the Hiroshima Prefecture. The company currently imports some 210,000 t/y of LNG from Indonesia.

The two companies have also signed a memorandum of agreement (MoA) with the City of Sendai that allows for the use of the LNG vessel to deliver the LNG to Hiroshima Gas. The MoA is significant in that it is the first time that an LNG supplier and two customers have agreed to the mutual use of one dedicated vessel to transport LNG to the customers' respective receiving terminals.

Latest European Union news

A proactive competition inquiry has been launched into the European Union's (EU) natural gas sector, with the aim of rooting out anti-competitive practices, writes *Keith Nuthall*. If the European Commission (EC) discovers instances of gas companies breaking existing EU competition law, legal action could follow. Also, if Brussels concludes that competition problems are being caused by lawful means within the gas sector, it could propose legislative reforms. The Commission is concerned about current and projected rises in gas prices. An interim report will be issued this year; a final report next year. The inquiry comes as the EU Council of Ministers has approved a regulation harmonising third-party access to European gas networks, creating rules on charges, capacity allocation, congestion management and other issues.

In other EU news:

- The Commission has scrapped a competition inquiry into the relationship between Germany's Ruhrgas and Russia's Gazprom. This follows their agreement that Ruhrgas would no longer be blocked from re-exporting Gazprom gas and Gazprom would not regard Ruhrgas as its 'most favoured' German customer.
- Meanwhile, Brussels has launched an investigation into the planned acquisition by German energy group E.ON of the gas wholesale and storage arms of Hungarian oil and gas group MOL. The Commission has 'significant competition concerns' about the Hungarian gas market.
- The European Bank for Reconstruction and Development (EBRD) and the World Bank's International Finance Corporation are both taking a 5.1% stake in Romanian gas distribution company Distrigaz Sud, which is now controlled by Gaz de France International.
- The discharge of pollution within EU seas has been criminalised if carried out with intent, recklessly or negligently. A directive agreed by the EU Council of Ministers says member states must impose 'effective, dissuasive and proportionate sanctions'.
- The European Investment Bank (EIB) is planning to lend the Public Gas Corporation of Greece (DEPA) 22mn to build a key underground high pressure gas pipeline connecting with the Turkish network via Komotini. The bank also plans to lend DEPA 25mn to increase the capacity of its LNG terminal at Revithoussa island, near Athens.
- The EIB is lending the Egyptian Natural Gas Company (GASCO) 50mn to build two gas pipelines running a total of 152 km within Egypt.
- Ireland, Spain, Estonia and Luxembourg are being taken to the European Court of Justice (ECJ) by the Commission for failing to properly implement the key gas internal market directive, liberalising trade across Europe. Italy is being brought before the court for failing to impose minimum EU taxation rates on natural gas.
- The Commission is threatening France, Estonia, Finland, Greece, Italy, Luxembourg, the Netherlands, Portugal and Slovenia with legal action over their failure to implement the EU biofuels directive that encourages production of alternative fuels.
- Brussels has also approved the acquisition of joint control of the UK's Edinburgh Oil & Gas by Dutch energy companies Oranje-Nassau Group and SHV Holdings.
- Germany has been authorised by the Commission to subsidise the biofuel subsidiary of national sugar giant Südzucker with 43mn for a plant producing bioethanol from cereals and sugar treacle.
- An EU research project is developing an information technology system that will provide real time advice to emergency services on reducing the damage from maritime disasters, such as oil spills. For more details, visit **www.nersc.no/Projects.dismar**

IN BRIEF

UK

Greenergy reports that it is now able to *offer customers in north-west England its low cost diesel and petrol from the Kaneb terminal at Eastham in Cheshire. The new tankage is in addition to existing facilities in the south-east, which typically supply some 50mn litres of fuel per week to a variety of forecourt operators and commercial customers. The first retail customer for the new tankage facility is Tesco, in a deal to supply 31 forecourts across the north-west of England and north Wales.*

A new colour-coded environment *label for all new cars began to appear in new car showrooms in the UK on 1 July 2005. The consumer-friendly label is designed to help car buyers assess the climate change impacts of different cars. The label will also show how car buyers can cut their running costs if they buy a lower carbon car. (See* Petroleum Review, *April 2005 for more information).*

In a recent PricewaterhouseCoopers/ *Futures and Options Association (FOA) survey – entitled* End users and derivatives: Current and future trends *– which was conducted on an informal basis amongst a small number of key market participants and end-users, regulation was agreed by both groups as the single greatest challenge facing the derivatives markets. A copy of the report's Executive Summary can be viewed at* **www.foa.co.uk/publications/pwcsurvey_june05.pdf**

EUROPE

Sweden will this September launch a *passenger train powered by biogas alone, reports* Keith Nuthall. *Developed by Svensk Biogas for SKr10mn (£750,000), the train will carry up to 54 passengers along Sweden's east coast. For more details, visit* **www.svenskbiogas.se**

Shell is to exchange a 20% stake in its *Rome refinery, Raffineria Di Roma, for Total's 18% interest in Reichstett refinery, Compagnie Rhenane de Raffinage.*

Total has signed a memorandum of *understanding (MoU) with the Finnish oil company, Neste Oil, with the aim of jointly studying the possibility of building a production plant for a new generation biodiesel product. The unit would be located in Europe, in one of Total's refineries, and is expected to begin production in 2008.*

Centrica and GdF buy Belgian

Centrica reports that through a 50:50 joint venture with Gaz de France it has conditionally agreed to acquire a controlling 51% stake in Belgian energy company SPE (SPE), in a deal valued at 760mn (£507mn).

At the same time, Centrica's existing Luminus 50:50 joint venture energy supply business in Belgium and ALG Nègoce, Gaz de France's 50:50 retail joint venture in Belgium, will be acquired by SPE for shares, valuing the entities at 207mn (£138mn) and 2mn (£1.3mn) respectively. The 49% balance of the enlarged SPE will be held by existing Belgian shareholders of SPE, Publilum (Centrica's existing partner in Luminus) and ALG.

SPE is the second largest power generation company in Belgium, with around 1.6 GW of principally gas-fired production capacity and around 400 MW of capacity secured under long-term procurement contracts. The company currently has a customer base of around 50,000 accounts, comprising mainly Flemish electricity customers. It has also secured default supply rights for a further 370,000 electricity customers, most of whom are expected to transfer to SPE when the residential energy market in Wallonia opens in January 2007.

Luminus currently supplies around 800,000 energy customer accounts, primarily in Flanders. ALG Nègoce has acquired default supply rights to around 180,000 gas customers, most of whom are expected to transfer to the company when the Wallonian market opens. The enlarged SPE business is therefore expected to have a customer base of around 1.4mn energy accounts in 2007, a retail market share of nearly 20%, with overall generation capacity and consumption broadly matching.

New entrant in UK bioethanol market

Green Spirit Fuels is a new company launched by grain trader Wessex Grain. The company has been founded to produce and market bioethanol – initially through its subsidiary Wessex Biofuels, which is in the process of obtaining planning permission for a bioethanol plant to be built adjacent to the current Wessex Grain site. The proposed Henstridge plant will produce 130mn l/y of bioethanol.

Green Spirit Fuels plans to be the first to produce bioethanol in the UK, and will eventually operate on a number of sites using locally produced feedstocks – principally wheat. It is anticipated that the first plant will commence production in 2007.

According to Malcolm Shepherd, Managing Director of Green Spirit Fuels and Wessex Grain: 'The establishment of Green Spirit Fuels is the next step in a process of making UK-based production [of bioethanol] a reality. For consumers, it offers considerable environmental advantages, helping the government to meet its targets on climate change as well as the EU objectives for the inclusion of biofuels. For UK growers, bioethanol production could use a large proportion, if not all, of the current exportable surplus of wheat. This would bring stability to the market as well as reducing transport costs.'

Wessex Grain is one of the top-ten grain traders in the UK, currently handling more than 400,000 tonnes of cereals, oilseeds and pulses annually in the south and south-west of England. Its traditional customers are animal feed millers, flour millers and maltsters, both in the UK and Europe. However, Wessex has spent some years exploring the possibility of a viable bioethanol industry in the UK, including research in Sweden and Spain, where there is a strong market for bioethanol. Standard unleaded petrol (EN228) can include 5% bioethanol and is therefore able to be used in all modern cars.

Bioethanol offers a number of clear environmental benefits over traditional petrol. Recent research conducted by the Central Science Laboratory on behalf of HGCA (Home Grown Cereals Authority) showed that: 'Compared to fossil-derived petrol, bioethanol from wheat has the potential to reduce energy inputs by 61% and total greenhouse gas emissions by 65% for each MJ of energy created.' Bioethanol also burns more cleanly and is a more efficient fuel. (A summary of the HGCA study can be obtained from www.hgca.com**)**

Bioethanol has enjoyed a discounted rate of duty at the pump since January this year – 20 pence less per litre than petrol. The government is working towards meeting the targets set by the EU of 5.75% of transport fuels to come from biofuels (bioethanol and biodiesel) or other renewable sources by the year 2010.

The potential to introduce a Renewable Transport Fuel Obligation to enforce the proportion of renewable fuels included in the petrol and diesel sold in this country was included in the Energy Act in 2004. It is widely anticipated that this will be implemented in the forthcoming budget.

Electricite de France (EdF) is understood to be planning to sell 65% of the capital of Edenor, Argentina's leading electricity distributor. Edenor is 90% owned by EdF, the remaining 10% held by staff. EdF will retain a 25% in Edenor.

***Borealis is to invest 36mn in expanding** its olefins unit in Porvoo, Finland, for completion during a planned turnaround in 2007. Ethylene capacity will increase from 330,000 t/y to 380,000 t/y and propylene capacity from 200,000 t/y to 223,000 t/y. Meanwhile, the International Petroleum Investment Company (IPIC) of Abu Dhabi and OMV of Austria have agreed to purchase Statoil's 50% shareholding in petrochemicals company Borealis for an undisclosed sum. Following the deal, the new Borealis ownership will be 65% IPIC and 35% OMV.*

EASTERN EUROPE

***The Czech Republic, Hungary, Poland** and Romania are the biggest consumers of motor fuel in Central and Eastern Europe (CEE), according to independent market analyst Datamonitor. Motor fuel consumption grew by an average of 3.4% between 2000 and 2004 in these markets, compared with a CEE average of 2.8%. 'Not only have these countries experienced tremendous growth, they also offer considerable potential for both existing fuel retailers and new entrants,' states Datamonitor. 'While market conditions vary widely, they can be assessed in terms of fuel, non-fuel and competitor intensity. As Western European markets have demonstrated, non-fuel interests are one way of supplementing wafer thin fuel profit margins. However, whilst 77% of service stations in the Czech Republic and Hungary have a forecourt store, only one in every two has a shop in Poland and Romania. As hypermarkets begin to gain a piece of the fuel retailing pie in the CEE, network rationalisation rather than expansion is the key to establishing a firm foothold in Europe's fastest developing regions.'*

NORTH AMERICA

***Researchers from Chevron and the** University of Kentucky have created car-lubricating oil from drinks bottles, detailing the technical methods in the American Chemical Society's journal* Energy & Fuels. *They converted 60% of the polyethylene plastic into a wax with the right molecular properties for further processing, writes* Monica Dobie. *Americans landfill 24 million tonnes of plastic annually.*

Gasoline remains US 'bargain fuel'

Despite recent price spikes, gasoline in the US remains relatively inexpensive in historical terms and in comparison to other consumer expenditures, according to an analysis by energy research firm John S. Herold. 'Even with unleaded regular selling for more than $2 per gallon, the increase in gasoline prices since 1982 is 25% lower than the increase in food prices, 50% lower than the rise in housing costs, 70% lower than the spike in medical costs and a huge 80% below the surge in college tuition,' the firm found.

In addition, factoring-in inflation and improved fuel mileage, the cost of gasoline per mile driven is less than half of 1981 rates, and represents less than 15% of the average yearly cost of operating a full-size passenger car.

Herold's Co-Director of Research, Nick Cacchione, describes gasoline as 'America's bargain liquid' on a per-barrel basis, pointing out that is is 10% cheaper than bottled water, one-third the cost of milk, one-fifth the cost of beer and less than 2% of the price of a bottle of Jack Daniels.

Carbon-free electricity from hydrogen

BP, ConocoPhillips, Shell and Scottish and Southern Energy (SSE) are to commence engineering design of what is claimed will be the world's first industrial scale project to generate 'carbon-free' electricity from hydrogen. The planned project – producing 'decarbonised' fuel and using it for power generation – would convert natural gas to hydrogen and carbon dioxide (CO_2) gases, then use the hydrogen gas as fuel for a 350-MW power station, and export the CO_2 to a North Sea oil reservoir for increased oil recovery and ultimate storage. It is claimed that the project would reduce the amount of CO_2 emitted to the atmosphere by the power generation by over 90%. While each of the component technologies making up the project is already proven, their proposed combination in this project is a world first.

Initial engineering feasibility studies into the project have already been completed. The partners will now carry out further detailed front-end engineering design work with the aim of confirming the economic feasibility of the scheme. This work is expected to be complete in 2H2006. This will allow a final investment decision to be taken next year, subject to which the project would then be expected to commence operation in 2009.

The full project would require total capital investment of some $600mn. It would also require an appropriate policy and regulatory framework that encourages the capture of carbon from fossil fuel-based electricity generation and its long-term storage.

When fully operational, the project is expected to capture and store around 1.3mn t/y of CO_2 and provide 'carbon-free' electricity to the equivalent of a quarter of a million UK homes. It will be located close to Peterhead in north-east Scotland. A newly built reformer plant will convert up to 70mn cf/d of natural gas into CO_2 and hydrogen, with the hydrogen used as fuel for a new 350-MW combined cycle gas turbine power station.

It is proposed that the CO_2 generated by the reformer be exported and reinjected into the mature BP-operated Miller oil field, where it would be stored and could help to increase oil recovery. Miller is currently due to cease production in 2006/2007. However, the injection of CO_2 into the reservoir could increase the amount of oil extracted from the field, potentially allowing the production of up to 40mn additional barrels of oil and extending the life of the field by 15 to 20 years.

Venezuela proposes regional oil alliance

Venezuelan President Hugo Chavez is understood to have unveiled a regional oil alliance to provide fuel at cheaper prices to 15 Caribbean nations. The Petrocaribe initiative aims to further cut the preferential prices Venezuela gives to communist Cuba and other nations. State oil firm PdVSA is reported to have already created an affiliate, PdV Caribe, to implement the initiative.

Venezuela is investing some $50mn in a fund to start the programme, which will pay for oil shipments and help establish storage facilities across the region. Chavez pledged highly preferential oil prices, with Caracas picking up 40% of the cost if oil was selling at more than $50/b. He promised further concessions to the Petrocaribe signatories if prices hit the $100/b mark. All business conducted under the new initiative will be between governments, not private companies, stated Chavez.

Inergy is reportedly acquiring the *Stagecoach natural gas storage facility in New York State for about $205mn. The company is also understood to have bought the rights to expand the facility for $25mn.*

Chevron has announced today plans to *increase the capacity of the Pascagoula, Mississippi, refinery's fluid catalytic cracking unit (FCCU) by about 25%, from a current capacity of 63,000 b/d. The project will increase the plant's gasoline production by 500,000 gallons per day at a cost of some $150mn.*

RUSSIA/CENTRAL ASIA

The World Bank is giving Tajikistan *$15mn to help improve its gas and electricity distribution systems, which have been deteriorating since it gained independence in 1991, reports* Keith Nuthall.

Lukoil claims to be the first Russian *oil company to have commenced large-scale production of a low-sulphur, environment friendly diesel fuel – called Lukoil Euro-4 – and launched it to the market. The fuel meets the European environment requirements for EN-590:2004 (Euro-4) diesel fuel. The fuel contains only 0.005% of sulphur – 40 times lower than specified by the Russian GOST 305-82 standard.*

ASIA-PACIFIC

BP, Sinopec and Shanghai *Petrochemical Company – the three parties in the SECCO joint venture – have commissioned the SECCO petrochemicals complex in Shanghai. The 220-hectare facility, reportedly the largest petrochemical complex in China to date, was built in just 27 months, three months ahead of schedule. Commissioning of the 900,000-t/y cracker earlier this year took just 10 hours and 45 minutes – a world record.*

WORLD

The UN Conference on Trade and *Development (UNCTAD) agency has set up a biofuels initiative to encourage the production of such alternative fuels in developing countries, writes* Keith Nuthall. *An international group of experts will help develop manufacturing plants and technology, advising on handling biofuel exports.*

World utilities under pressure

The world's utilities market is facing a major investment challenge that is intensifying blackout fears and the renewables challenge facing industry leaders, according to PricewaterhouseCoopers' seventh annual global utilities survey entitled *Under Pressure*. According to the report, regulatory worries top the list of concerns expressed by investors about funding the industry. While a majority of investors believe deregulation is helping the investor climate, more than a third (39%) say market reforms are damaging confidence, highlighting the dangers of inconsistent regulation, energy, tax and environmental policies.

This anxiety within the utilities industry means that despite its growth prospects, it is failing to attract the investment it needs. Meeting projected supply needs will require an investment of $12.7tn in the period to 2030 in the power generation, transmission and distribution and gas-supply infrastructure (according to the International Energy Agency/OECD *World Energy Outlook* 2004 report). However, the utilities sector is failing to rise above the pack when it comes to attracting investment. The PricewaterhouseCoopers report finds that the utilities sector is rated as attractive as several other sectors, including financial services, consumer and retail and pharmaceuticals. Worryingly, this was the sentiment echoed by investors that already focused on utilities.

Utility leaders feel that without regulatory certainty and high levels of investment, blackouts could become a more frequent occurrence. In fact, two-thirds of utility company respondents in the report believe the likelihood of blackouts will increase or remain the same. These concerns about security of supply are spreading across the industry. Nearly three-quarters (72%) of utility company respondents say supply security and transmission capacity are major concerns facing the sector – up from 65% in 2004. The regulatory uncertainty is also affecting investment in renewables. While the focus on renewables is increasing, with the industry trying to change the fuel mix, investors feel this area will face the biggest funding challenge creating a new vulnerability for the sector. In this climate, more than half (52%) of utility respondents expect a nuclear revival.

Manfred Wiegand, Global Utilities Leader, PricewaterhouseCoopers, commented: 'The challenge for the utilities sector is immense. We urge governments, utility companies, investors and consumers to work together to find a truly sustainable and long-term strategy for the industry. This means getting the equation right in the market through a balanced view of renewables and a streamlined regulatory environment, generating market rates of return for investors and encouraging transparent and well-communicated business strategy among utility companies.'

UK diesel tank exemption extended

The UK Freight Transport Association (FTA) has been successful in persuading the Department for Transport (DfT) to extend the existing exemption from the requirement for an emergency telephone number on diesel tanks until 30 June 2006. The exemption was due to have expired on 1 July 2005. 'This represents an important cost saving to affected sectors, particularly the construction, plant and utilities sectors as otherwise there would have had to be 24-hour manned emergency telephone numbers provided either directly or via an agency commercial agreement with, for example, the National Chemical Emergency Centre,' states the FTA.

It should be noted, however, that the general exemption from ADR driver training for carriage of diesel ceased on 30 June. By that date, those carrying diesel in UN-approved drums or intermediate bulk containers (IBCs) in excess of 1,000 litres will have had to have had their drivers trained and certificated on approved courses. ADR driver training requirements also apply to carriage in old tanks or ADR/UN certified tanks.

Power station proposals for Mongstad

An application to build a combined heat and power station at the Mongstad refinery near Bergen is being submitted by Statoil to the Norwegian Water Resources and Energy Directorate (NVE). A revised request for a renewed emissions permit covering Mongstad, including the new power station, will also be sent to the Norwegian Pollution Control Authority (SFT).

The proposed heat and power station would be fuelled by Troll gas piped from the Kollsnes processing plant further south and by surplus gas from the refinery. The project is being developed as part of efforts to strengthen, continue developing and enhance energy efficiency at Mongstad, and also to ensure long-term electricity supplies for the Troll field – which faces growing power requirements in coming years, states Statoil.

Built to order

Overview of Noord Natie/A4S' bulk storage facilities in Antwerp

Photo: Noord Natie

The opening this month of the first grassroots bulk liquids terminal in north-west Europe in a generation sets the seal on what has been a very good year for operators. Peter Mackay* *reports.*

Oiltanking's new chemical terminal at Terneuzen, in the Netherlands, opened for business this month, offering 156,000 cm of new tankage for chemical products. It is primarily intended to service the Dow Chemical plant next door but, with plans to more than double capacity in the near term, third-party business will also be handled.

The Terneuzen facility is the first significant grassroots terminal to be built in north-west Europe since the late 1980s. However, it is unlikely to stay the newest site for long, since other operators are eyeing new projects, not least in Antwerp where the left bank of the Scheldt is being opened up to industrial development. Vopak has acquired a 17.4-hectare site there and plans to commission a new terminal in the second half of 2007, with the first phase of construction offering 109,000 cm of chemical storage capacity in 74 tanks.

These two projects are significant because they stand in sharp contrast to received wisdom that Asia is where the action really is, and that any expansion in demand for tank storage services in northern Europe is going to derive primarily from rising Russian exports of fuel oil.

Which is not to say that Asia and Russia are not the major factors at play in the terminals sector today. For instance, before Vopak opens its new Antwerp site in a couple of years' time, it will have already completed new terminals in Shanghai (already partly open), Singapore (its fourth site, on Banyan Island) and Darwin, Australia. In addition, the company reports rapid increases in throughput of fuel oil in Rotterdam, largely as a result of Russian exports being stored for bulking to larger parcels for onward shipment to Asia. Throughput is also up at its Tallinn site in Estonia, used partly to handle Russian exports.

A brief look at Vopak's financial results for 2004 shows that its most exciting areas of operation are Asia and its oil business in Europe, the Middle East and Africa (EMEA). Nevertheless, the investment in new chemical capacity by Vopak and Oiltanking – the two largest providers of third-party tank storage services in the world – shows commitment and confidence in the European chemical industry.

Come to Antwerp

In the tank storage business, location is everything. It is hard to relocate a tank once it is in place, so investment decisions need to be thought out in the light of anticipated demand over decades. It is therefore interesting to see the focus of terminal development in northern Europe being fixed very firmly on the River Scheldt, both in Terneuzen and over the Belgian border in Antwerp. In addition to the new Vopak project, French operator Rubis Terminal has a new facility planned for the left bank, in the Doeldock. Construction is due to start next year and the 132,000-cm facility should open by mid-2007. Its 52 tanks will all be in stainless steel and will serve the chemical market.

The only existing terminal on the left bank, ADPO's site at Kallo, was recently expanded and the operator is currently adding new warehousing and drumming capacity. ADPO is also considering plans to use some spare land to expand overall capacity by 140,000 cm. In central Antwerp, Noord Natie is upgrading some of its tanks and has obtained permission to store dangerous chemicals. It is also studying the possibility of expanding capacity by some 100,000 cm, again for chemicals. LBC is also upgrading its Antwerp site.

While it certainly seems to be the case that the chemical storage sector is concentrating on Antwerp, that does not mean that Rotterdam is being left out of the picture entirely. LBC has just installed a new vapour control system to allow it to handle chlorinated solvents at its Rotterdam terminal, where additional warehousing and drumming space has also been added.

Still, the focus of development in Rotterdam remains in the oil sector, where Vopak is investing around 55mn at its Europoort oil terminal. Work includes the construction of a fourth jetty, expansion of capacity to blend oil products, and the conversion of some 345,000 cm of tankage to handle fuel oil and jet fuel. Vopak has recently announced a major new contract with KPC affiliate Q8 Aviation to handle jet fuel imports from Kuwait to help meet rapidly rising demand in Europe. Around 1mn t/y are likely to pass through the terminal from next year, for pipeline delivery to airports at Amsterdam, Brussels and Frankfurt.

North and south

Further investment is being made in the Baltic to cope with expanding volumes of oil coming out of Russia. As well as Rotterdam, Gothenburg is also being used as a storage zone for the bulking of export cargoes and Nordic Storage is planning to build 400,000 cm of new tankage and/or a major underground cavern storage facility to help meet demand. It is also expanding bunker capacity at its Skarvik 2 terminal in Gothenburg to help service these trades.

Elsewhere in the Baltic, Pakterminal has added four large tanks, expanding capacity by 55,000 cm, and Baltic Tank has built new tanks for both chemicals and petroleum products at its Kunda terminal in Estonia and the Rauma facility in Finland.

By contrast, the pace of activity in southern Europe has been slow over the past year. Some new tanks have gone up in Spain, with Tepsa adding to capacity at its Bilbao terminal and Terquimsa expanding at Tarragona. Tepsa is currently looking at further expansion of its Bilbao and Valencia terminals, the latter for bunkering purposes. Vopak is also currently considering a plan to establish a new terminal at Algeciras, partly to offer a bunkering service but partly also for breaking bulk prior to local distribution and to handle product imports into Spain. The facility would have a capacity at start-up of some 200,000 cm.

Further into the Mediterranean, Solventas is part way through an 80,000 cm expansion of its Gebze site to handle rising petroleum product imports into Turkey.

New business

There has also been very little activity in the UK over the past year. The main development of interest has been the contract between Simon Storage and Biofuels Corporation regarding the construction of a biodiesel plant at Simon's Seal Sands terminal in Teesside, which is due for start-up later this year. Around

Call to cut inland oil and fuel spills in England and Wales

Consultant Oakdene Hollins recently issued a report entitled *An Analysis of Inland Oil and Fuel Incidents in England and Wales,* highlighting how inland oil and fuel spillage incidents can be reduced. The report – which was commissioned by the Oil Care Campaign (OCC), whose members include Defra (Department for Environment, Food and Rural Affairs), the Environment Agency, SEPA (Scottish Environment Protection Agency) and Shell UK – found that there are around 800 serious incidents caused by oil or fuel in England and Wales each year, of which over 70% of the most serious incidents are never reported to the Environment Agency.

Four significant causal factors were identified, accounting for over half the serious incidents and 30% of minor incidents – tank failure, the overfilling of tanks, pipe failure and vehicle fuel tank failures. The study recommends that focus be placed on capturing more incident data on formal systems. It also suggests:

- Implementing a certification scheme for all oil tanks.
- Amending building regulations to require oil tanks to be failsafe.
- Extending oil storage regulations to houses as well as businesses.

A full copy of the report can found at **www.environment-agency.gov.uk/oilcare**

In response to the report, the Environmental Industries Commission (EIC) has called for 'urgent action to tackle inland oil spills', which it states is 'one of the biggest causes of pollution incidents in the UK'.

According to the EIC, the Environment Agency has been working under the assumption that there were over 4,700 inland oil spills in 2003 – 15% of all pollution incidents. However the new report shows that the real picture is much worse as the National Incident Recording System captures just 23% of serious inland oil spills.

New oil storage regulations (The Control of Pollution (Oil Storage) (England) 2001 Regulations) are currently being phased in – covering new tanks from 1 March 2002, tanks with 'significant risk' from 1 September 2003 and all other existing tanks from 1 September 2005 – the aim to 'reduce the number of oil-related water pollution incidents by the year 2005 by about half compared to 1999 levels'. However the new report shows that official statistics greatly underestimate the number of pollution incidents. Even on official statistics incidents have so far fallen less than 10%, from about 5,000 in 1999 to 4,700 in 2003.

Last year an EIC report, entitled *Oil Under the Carpet*, revealed that the UK government had given the Environment Agency no money for a dedicated programme of inspections of the 800,000 oil storage tanks that come under the oil storage regulations, undermining its effectiveness. The report, and subsequent high-level campaign, called on the government to:

- Require the Environment Agency to put in place a targeted inspection and enforcement strategy for the oil storage regulations – and give them funding to carry it out.
- Expand the regulations to cover the millions of domestic, agricultural, waste oil and underground storage tanks currently excluded.
- Put in place a statutory 'MOT'-style inspection regime for oil storage tanks.
- Put the Environment Agency pollution prevention guidelines on a statutory footing.

Photo: Oiltanking

Oiltanking's new chemical terminal under construction at Terneuzen, the Netherlands, is the first significant grassroots terminal to be built in north-west Europe since the late 1980s

250,000 tonnes of vegoils will be handled by Simon each year to provide feedstock to the plant.

Biodiesel and other 'new' products are likely to offer growing business for terminal operators in Europe over the coming years. However, the European industry is lagging some way behind the situation in the US, where terminal operators are getting used to coping with a wide range of products. In addition to 'boutique' gasolines, the introduction of progressively stricter sulphur limits on diesel fuels will expand the number of grades that need to be handled and raise problems of possible contamination during storage or handling. Furthermore, increasing volumes of ethanol are being moved around the US to replace MTBE as a gasoline oxygenator.

The US has had a significant impact on the European terminalling industry over the past couple of years in another respect. Three operators – Simon Storage, LBC and Petroplus – have recently been the subjects of buyouts by US equity investment firms, while Kaneb (formerly ST Services) has been in protracted discussions towards a merger with Valero, which was only finally effected at the start of July.

Both Simon and LBC are highly profitable and were bought out from parent companies facing financial problems elsewhere. Simon has done very little since, apart from the Biofuels contract, and LBC has undergone a period of adjustment from which it is only now emerging. LBC says it can expand overall capacity by 20% or more purely by adding tanks at its existing sites and it has already embarked on an expansion project in Houston. Petroplus, which has interests in refining and marketing and is also involved in the development of the Dragon LNG project in Wales, was in financial difficulties of its own and sought out a partner. It has concentrated lately on disposals rather than investments.

Ask the experts

It is clear that when oil or chemical companies are planning to start up new production facilities or expand distribution of their products, their reaction to the question of how to store liquid products in bulk is to look for outside help. The new Oiltanking site at Terneuzen is a case in point. When Dow first decided to undertake a major expansion at its plant, it looked for a partner with terminalling experience. Using the services of a third party clearly keeps the costs of constructing a new terminal off the books of the producer; on the other hand, the terminal operator can borrow the costs of construction against the promise of contract business over a long period.

Perhaps more importantly, however, the operation of liquids terminals in Europe is bound around by an increasing range of legislation and therefore demands specialist technical know-how. The entry into force on 30 June 2005 of amendments to the Seveso II Directive in EU countries has broadened the scope of the regulations and brought a number of smaller terminals in scope, and elevated others from 'lower tier' to 'top tier' sites. A particular focus of the amendment was on substances hazardous to the environment, so terminals that handle such products are among those most affected. There have also been changes to the notification requirements for petroleum products and the overall thresholds for such products have been halved.

Europe's terminals are also likely to be affected by the EU's incoming Registration, Evaluation and Authorisation of Chemicals (REACH) initiative, compliance with which is likely to be tiresome and costly, and the Integrated Pollution Prevention and Control (IPPC) Directive, which is already in place but which could result in the definition of new requirements for all industrial (and non-industrial) activities that generate pollution.

As the burden of compliance with legislation of this type continues to grow, cargo owners will look increasingly to companies with specialist knowledge at all stages of the supply chain. It is fortunate for terminal operators that the added costs that are loaded on them by the effort to comply are being offset by increasing business arising from widening trade imbalances and the demand for their expertise. Given that the emergence of China is having a profound impact on oil and chemical trades and that this effect is not expected to ease any time soon, it looks likely that terminal companies will be well placed to benefit from these trends for some time to come.

**Peter Mackay is Managing Editor of* Hazardous Cargo Bulletin, *an international magazine focusing on the oil and chemical supply chain.*

European bulk storage directory

Petroleum Review's European bulk storage directory is a detailed listing of the key players, including contact details and facilities/services offered, that can be accessed by EI members from the EI website at **www.energyinst.org.uk**
Regularly updated, the directory is fully searchable via a range of keywords.

If you would like to update your company's entry, or to be added to the database, please contact Deborah Wilson on t: +44 (0)20 7467 7115 or e: **dwilson@energyinst.org.uk**

Outlook for gas storage in Europe

One of the most important roles for an integrated gas company operating in a traditional, managed gas market is to ensure that demand and supply is balanced in the most cost effective, reliable manner. Gas storage has long been seen as key to achieving this. As gas markets liberalise this balancing requirement remains in place, but the role of storage has widened as company activities are unbundled and new players enter the market. Here, Chris Le Fevre, *Senior Consultant at Gas Strategies* examines how the role of storage has evolved in the European market and looks at future trends as competition develops.*

Gas producers and transporters like to supply gas at steady, preferably high, rates of flow while gas consumers, of course, want to use gas when they need it. This inevitable mismatch of supply and demand can be managed in a number of ways. In traditional, monopolistic markets the integrated gas company will be responsible for this activity and underground gas storage often plays an important role. In addition to providing the ability to balance loads, storage can also provide transmission support (whereby storage is sized and located to cover peak requirements, allowing more cost effective design and utilisation of the pipeline grid) and, in some cases, underpin security of supply. In France for example, which is largely dependent on imported gas, storage acts as a buffer against the interruption of supplies.

In these managed markets, the size and location of storage facilities is primarily determined from an assessment of the technical requirements of the system, coupled with consideration of other factors such as the availability of swing from producers and proximity to supply.

With the introduction of competition and open access to transportation systems, the responsibilities for ensuring the system is balanced is often shared between the various categories of players. Transporters will usually retain the obligation to ensure physical balance is achieved – but this will often be through a variety of rules and incentive mechanisms on suppliers to ensure that their inputs match outputs. As a result, both transporters and suppliers will have requirements for flexibility and this flexibility will become a tradable commodity with a defined value. Of course, this change does not happen overnight – there is a transitional period during which various aspects of the market are opened up and the power of the incumbent is progressively curtailed. The impact on the value of flexibility as the market liberalises is illustrated below:

Market Phase	Managed monopoly	Transition	Fully liberalised
Value of flexibility	Unknown	Arbitrary	Market determined

Market evolution

How does the role of gas storage evolve during these phases? In the 'managed monopoly', as already indicated, storage is bundled within the monopoly provider's asset base. As the market enters 'transition' the incumbent will seek to protect the value of storage (and possibly other assets) by imposing strict balancing rules and restricting the availability of storage. Pressure from new entrants and regulators is likely to force either a relaxation in balancing requirements and/or access to storage on a non-discriminatory, transparent basis. This, in turn, creates a market-related value for storage. However, other sources of flexibility – such as producer swing, spot sales and purchases, and demand side interruption – are also likely to be available in competition to storage. The market will price these various alternatives and storage owners may experience a loss of revenue and asset value as a result.

All is not lost, however! Fully liberalised markets will also result in a higher degree of price volatility as gas contracts indexed to lagged oil product prices are replaced by contracts linked to liquid trading hubs – for example, Henry Hub and the NBP (national balancing point). Marketers and traders will buy storage to take advantage of seasonal or longer-term arbitrage opportunities – or to manage risk. Additional storage services such as parking, balancing and loaning are likely to emerge and so the demand for storage is likely to start to rise in line with increasing gas demand.

So, the liberalising journey for storage can be something of a roller coaster ride, during which either prices or usage can fall followed by a resurgence as new uses emerge.

Impact on Europe

Increasing gas demand coupled with the expected growth in imports are both drivers for increased investments in storage. The pace of liberalisation is likely to quicken, adding to the demand for storage to meet balancing requirements and exploit arbitrage opportunities. On the other hand, some systems may be over-provided with storage. This over provision could result in some temporary reduction in asset values as markets open up.

Some marginal investments in new storage are possible, although investors are likely to want to be sure that these are made on the basis of clear contractual commitments from users.

UK gas storage

The UK has, of course, been self-sufficient in gas for many years. The proximity of gas fields to the centres of demand and the ability of many of these fields to swing production from summer to winter has meant that the UK has relatively low levels of storage compared to many other European countries. The main facilities include the depleted Rough (offshore) and Hatfield Moor (onshore) fields, the Hornsey and Hole House salt caverns, and a number of LNG storage facilities located at what were the extremities of the National Transmission System (NTS).

The LNG storage sites, which take gas from the NTS and liquefy it, were designed to provide transmission support at very high levels of demand or in the event of system failures. The economics of this approach are such that LNG storage is not a realistic newbuild option today.

The Rough field is by far the largest UK gas storage facility, with a working capacity of nearly 3bn cm – almost ten times larger than Hornsea. Generally speaking, the LNG and the salt caverns are primarily used for short, relatively high volumes of production, whilst Rough is more suitable for sustained levels of production. This tends towards the categorisation of salt cavity facilities as peak day (or mid-range) storage, whilst Rough is classified as seasonal storage. In practise, the facilities are used interchangeably – although salt cavity lends itself to more frequent recycling and so can be more popular with traders.

When British Gas was first unbundled in 1994 storage facilities were treated as a transportation asset. Whilst third-party access was provided for, prices were based on a regulatory tariff that was calculated according to costs (operating and depreciation) and return on what transpired to be an unrealistically high regulated asset value (RAV). Shipper balancing rules were not strict and, as a result, non-British Gas use of storage was minimal.

Following the introduction of the Network Code, the then regulator (Ofgas) reviewed the operation of the storage market and concluded that British Gas had a dominant position in storage in a way that hindered the development of competition. Furthermore, prices for storage were too high and the range of services was too limited. Ofgas ruled that storage capacity should be auctioned, with the first one held in 1999. To begin with, all of capacity sold was at the reserve price – thereby exposing the significant degree of oversupply in storage capacity and asset values fell as a result.

A significant amount of corporate restructuring followed – BG Storage was

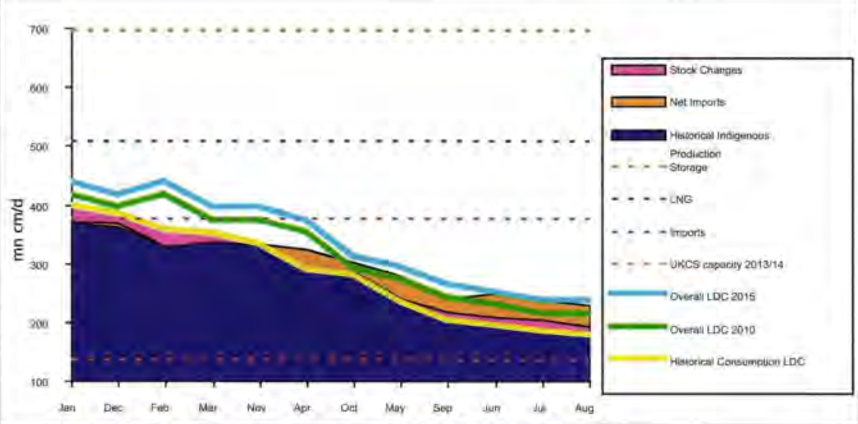

Figure 1: Likely gas demand and availability of flexibility to the UK market
Source: Gas Strategies' analysis of IEA data and Transco ten-year statement

sold initially to Dynegy, who then disposed of the two assets (Rough and Hornsea) to Centrica and SSE respectively. Centrica's acquisition of Rough led to a set of Competition Commission imposed undertakings relating to transparency and making capacity available in the market. Despite these restrictions the acquisition has been successful to date. Both usage and prices have increased – in the latter case the weighted average price for Rough has increased over four-fold and reported earnings have gone from a loss in 2000 to a £23mn profit in 2002.

This increase in performance has encouraged a wave of new storage developments. In addition to the Hole House and Hatfield Moor developments already onstream, a further range of depleted field and salt cavity facilities are either under construction or planned. If all of these are completed they will add capacity equivalent to approximately 70% of the Rough facility – although all of the new facilities will primarily be targeted at peak day rather than seasonal requirements. It is also worth noting that while the Rough, Hornsey and LNG storage assets are subjected to negotiated TPA (third-party access) new investments are, or are likely, to be exempt.

While storage will continue to face competition from imports from the Interconnector and other sources as well as demand side response, the inevitable decline in UKCS production (and, with it, beach swing) coupled with continuing concerns over spikes in the wholesale gas markets suggests that storage will continue to play an important role in any UK gas suppliers portfolio. **Figure 1** shows the likely demand and availability of flexibility to the UK market.

German experience

Germany is much more dependent on imported gas than the UK. The swing required is primarily provided by large storage investments and flexibility provided by the Groningen field in the Netherlands. Total storage capacity in Germany amounts to some 18bn cm, compared to 4bn cm in the UK. (See **Figure 2**.)

The regulatory treatment of storage in

continued on p45...

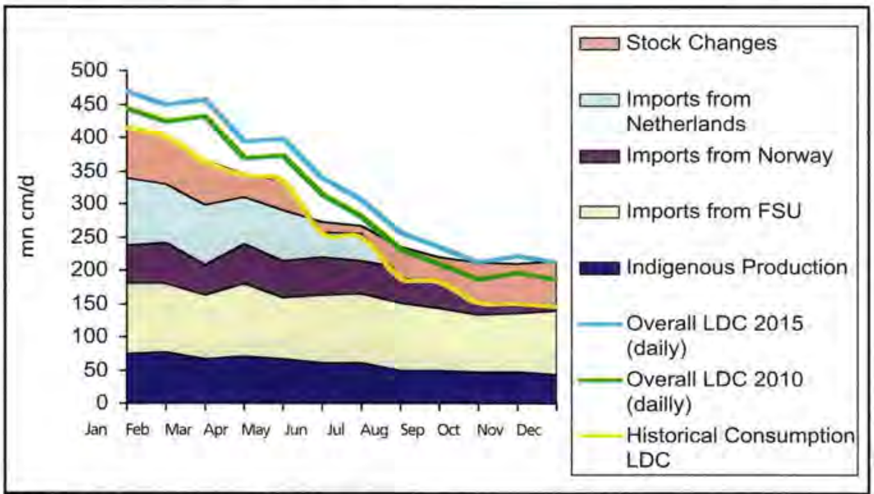

Figure 2: German seasonality sources *Source: Gas Strategies' analysis of IEA data*

US redoubles efforts to increase oil and gas production

The Gulf of Mexico deep waters were seen as the salvation for declining US oil and gas production when BP announced that it had found one large and one massive deepwater field in the late 1990s. However, enthusiasm has since waned in the absence of any further major deepwater discoveries despite intensive exploration. Judith Gurney *reports.*

Output in the Gulf's shallow waters has declined for a number of years. Major oil companies, including Chevron and Kerr-McGee, have divested their interests here, partly to focus on overseas projects. Statoil, which recently announced its intention of buying all of EnCana's Gulf of Mexico assets (see p22), is an outstanding exception.

Interest is now increasingly focused on ultra-deep waters. In the last five years, there have been 20 discoveries in water depths of more than 7,700 ft (see **Table 1**). Most of those made last year were drilled in water depths greater than 5,000 ft and several were in geologic formations older than those accounting for most Gulf of Mexico production to date. A few deepwater and ultra-deepwater discoveries have been announced so far this year.

Production continues

In March 2005, the US Minerals Management Service (MMS) reported 107 offshore Gulf of Mexico oil and gas projects on line, most with modest outputs – compared to 80 at the end of 2003 – with a dozen deepwater projects coming onstream last year. Two fields in the joint BP/Shell Nakika project in Mississippi Canyon began production, as did Shell's nearby Coulomb field. Other 2004 start-ups included the Llano field in Garden Banks; the Holstein, Marco Polo and Front Runner fields in Green Canyon; the Raptor and Harrier fields in East Breaks; and the Diana South field in Alaminos Canyon. None of these are major producers.

According to the MMS, seven or eight, mostly small, fields are due to begin operations in 2005, three in 2006 and eight in 2007. On the brighter side, two projects will soon improve offshore output considerably. BP's Mad Dog field came onstream in January and its Thunder Horse field – the largest discovery ever made in the Gulf of Mexico – is due to start up later this year.*

Development methods

Many new projects are developed using subsea systems tied back to established hubs and production structures with pipeline access to the shore. Extensive existing Gulf of Mexico infrastructure allows independent companies to develop modest finds which would not interest larger oil and gas companies.

Several new hubs are planned to serve ultra-deep and deepwater fields. The joint BP/Shell Nakika project in Mississippi Canyon will eventually be the gathering point for six fields using a permanently moored, semi-submersible floating production facility. Three of these fields came onstream in 2004 and the others are due to come on soon.

Independence Hub, designed by Enterprise Products Partners, will gather natural gas produced in seven deepwater fields. The producers originally involved included the designated operator Anadarko, along with Dominion, Kerr-McGee, Spinnaker and Devon Energy. The deep-draft, semi-submersible platform, to be located in Mississippi Canyon in water depths of approximately 8,000 ft, will have excess payload capacity to allow the tie-back of additional deepwater fields. Installation is slated for late 2006 and first production by mid-2007.

Spars, of which there are several versions in the Gulf, are often favoured for producing larger new fields. Four deepwater projects began production with spars in 2004 and early 2005, including Mad Dog with a truss spar. Several deepwater projects are developed with tension leg platforms (TLPs) and a few with semi-submersibles. Thunder Horse will have an enormous semi-submersible production unit that has been nearly four years in the making.

Cautious optimism

The MMS continues to describe the future of Gulf of Mexico exploration and production as 'very promising' and an 'expanding frontier'. But it is cautious regarding production forecasts.

Oil production in 2004 was lower than that of the previous three years and natural gas production the lowest it had been since 1986. Unless there are new major discoveries soon, once Thunder Horse and Mad Dog go into decline, oil production will begin to fall again.

The situation is worse for gas, as deepwater fields have been found, so far, to be oil prone. Some experts see Gulf of Mexico offshore gas output peaking at 5.3bn cf/d in 2004 and then declining to about 3bn cf/d in 2012.

Natural gas supply

With hopes fading that new offshore gas fields will be discovered to relieve current tight and volatile gas futures markets, focus is being directed elsewhere. Gas reserves are believed to exist offshore Florida, California, and parts of the east coast, but exploration and production is forbidden in these waters by long-standing federal moratoriums designed to protect beaches and coastlines from pollution.

Congress hopes to pass legislation permitting assessment of these reserves and the administration is trying to persuade coastal states to reduce their fierce opposition to exploration and production for offshore gas, if not for oil. This seems unlikely to happen, given the importance of tourism in these states.

Rocky Mountain reserves

The largest onshore gas reserve outside of Alaska lies in the Rocky Mountain area, but accessibility to this supply is also limited. Multiple-use interests and environmental concerns hamper exploitation here by restricting access and by enforcing strict regulations regarding exploration and production operations.

Much of the Rocky Mountain reserve, as in Texas and the south-west, lies in unconventional gas sources – tight-gas sands, coalbed methane and gas shale – which, unlike conventional reserves, are rarely located in concentrated formations. It usually requires a lot of wells drilled over a considerable area to empty a reservoir. Drilling in increasingly complex formations that yield less gas per well, combined with rising operating costs, limit the output of unconventional gas.

Alaska pipeline

Plans for a pipeline to bring stranded Alaska North Shore gas to the lower-48 states are more advanced than they have been for several years, following encouragement by Congress. However, they are proceeding slowly.

The planned 2,800-km, $20bn pipeline still requires assured investment and fiscal terms, as well as settlement of regulatory issues with the governments of Alaska, the Yukon Territory and British Columbia. At best, the line will be completed by 2015.

A Canadian pipeline to move gas from the northern Mackenzie Valley to Canadian and US markets is also moving slowly ahead, with some preliminary work already done.

Improved LNG outlook

The prospect of increasing gas supply with imported LNG is brighter, although the amounts involved are unlikely to be great. There are currently more than 30 proposals for the construction of new LNG import terminals and at least some of these will get built. The Federal Regulatory Commission has approved six proposals for the Gulf of Mexico, five onshore terminals and the experimental Port Pelican Energy Bridge that recently began operation. In addition, work has begun on increasing the capacity of the four existing conventional LNG terminals. (See **Table 2**.)

The Energy Bridge, located 116 miles off the coast of Louisiana, is the first new LNG terminal in the US for over 20 years. Built and operated by Excelerate, a company formed by personnel of El Paso's LNG division, it is the first testing of an innovative shipboard regasification technology and a submerged offloading buoy. Its volumes are relatively small, with output transported from the structure by an underwater pipeline to a major gas offshore pipeline system. If successful, other projects involving offshore LNG terminals will go probably go ahead.

The Gulf of Mexico is favoured for new terminals partly because there is lots of available capacity in major pipelines from the area to transport gas to most US markets, and partly because there is less local opposition to oil and gas oper-

Project	Operator	Block*	Water depth (ft)
Tobago	Shell	AC 859	9,627
Silvertip	Chevron	AC 815	9,226
Tiger	Chevron	AC 818	9,004
Cheyenne	Anadarko	LR 399	8,987
Atlas NW	Anadarko	LR 5	8,810
S Dashshund/ Mondo NW	Anadarko	WR 2	8,340
San Jacinto	Dominion	DC 618	7,850
Jack	Chevron	WR 759	6,965
La Femme	Newfield	MC 427	5,800
Thunder Hawk	Murphy	MC 734	5,724
Goldfinger	Dominion	MC 771	5,423
Ticonderoga	Kerr-McGee	GC 768	5,250
Puma	BP	GC 823	4,130
Dawson Deep	Kerr-McGee	GB 625	2,900
Crested Butte	Nexen	GC 242	2,846

** AC = Alaminos Canyon, DC = Desoto Canyon, GB = Garden Banks, GC = Green Canyon, LR = Lloyd Ridge, MC = Mississippi Canyon, WR = Walker Ridge*
Source: US Minerals Management Service

Table 1: 2004 Gulf of Mexico deepwater discoveries

Project	Company*	Block site**	Facility type
Energy Bridge	Excelerate Energy	WC 603	Submerged turret buoy
Port Pelican	Port Pelican	V 140	Gravity-based structures
Gulf Landing	Gulf Landing	WC 213	Gravity-based structures
Main Pass Energy Hub	Freeport-McMoRan Energy	MP 299	New and existing structures
Pearl Crossing	Pearl Crossing LNG Terminal	WC 220	Gravity-based structures
Compass Port	Compass Port	M 910	Gravity-based structures
Beacon Port	Beacon Port	WC 167	Gravity-based structures

**Port Pelican is an affiliate of Chevron; Gulf Landing is a subsidiary of Shell; Pearl Crossing is a subsidiary of ExxonMobil; Compass Port and Beacon Port are subsidiaries of ConocoPhillips*

***M = Mobile, MP = Main Pass, V = Vermilion, WC = West Cameron areas*
Source: US Minerals Management Service

Table 2: Proposed offshore LNG projects in the Gulf of Mexico

ations. Smaller terminals have been proposed for Baja California in Mexico and in north-east Canada to serve niche US markets, using spare capacity in existing pipelines. A similar niche market in Florida is expected to be supplied with LNG landed in the Bahamas and pipelined to the US mainland.

LNG terminal proposals in the US require not only federal but also local and state approval regarding safety standards for design, construction and operation procedures, as well as a legal and fiscal framework for new projects. Congress hopes to pass legislation giving the federal government exclusive authority for siting and regulating LNG terminals, but it is questionable if this will happen given strong opposition to terminal construction along both the east and west coasts.

The absence in Canada of a national regulatory body for LNG terminals makes it easier for projects to proceed there. Companies have proposed six terminals in New Brunswick and Nova Scotia and only one is facing significant local opposition. Mexico has given permission to Chevron for an offshore Baja terminal near Coronado Islands and to Sempra for an onshore terminal, but the regulatory authorities have threatened to halt construction on the latter.

Refinery shortage

Concern over US oil supply is compounded by a very tight products market, with refineries running at close to full capacity and no new plants built since 1976. Any reduction in product output as a result of refinery shutdowns for repairs has an immediate effect on product prices.

Tightness in the domestic refined products market is relatively recent. For years, the refinery industry struggled with excess capacity and low return on investment, and the sale and closure of plants reduced the number of refineries from 325 in 1981 to the present 149. Federal and state regulations, especially those concerning clean fuel requirements, have been an important factor in discouraging expansion in an industry faced with an increasingly sour slate of available crude. Many refineries are unable to process heavy, high-sulphur crude without undergoing extensive and expensive upgrades. Concern that demand and high returns on investment may not prevail are also deterrents.

A handful of major oil companies now control more than half of total US refining capacity and most of these companies are reluctant to invest in this side of their businesses. An outstanding exception is independent Valero Energy, which had one refinery in 1997 and now has 19 following its acquisition of Ultramar Diamond Shamrock in 2001 and of Premcor this year. Valero's strategy has been one of buying relatively inexpensive refineries and upgrading them to process sour crude.

Aware of the impact of refinery shortage on petrol prices to which the US public is especially sensitive, President Bush has expressed alarm regarding refinery shortage. He has suggested that one solution could be to construct new refineries on the sites of military bases scheduled for closure, and has called for a simplified construction permitting process. However, it is doubtful if many of these military sites are located sufficiently close to the necessary crude and product pipeline systems to make this a viable option.

Moreover, most analysts believe that growth in refining capacity is more likely to occur by modernising existing facilities than by grassroots construction, as building a new plant has been estimated at three to four times the cost of expanding an existing plant. Simplified and less restrictive state, as well as federal, regulations will be necessary to persuade companies to make the necessary investments for upgrading.

Energy legislation at last?

President Bush failed to get his energy programme enacted in his first administration. This time around, with increased Republican control of Congress, he has a better chance. However, the contentious issues that defeated past energy bills may do the same this year. These include opening the ANWR (Arctic National Wildlife Refuge) for exploration; relaxing moratoriums on exploration and production offshore Florida, California, and some of the east coast; mandatory increased use of renewable energy sources by electric utilities; financial support for new nuclear plants; mandatory increased use of ethanol as a fuel additive; and protection from liability for oil companies for MTBE pollution.

Even if compromises on these issues are reached to allow the passage of an energy bill, the strength of local, state and environmental group opposition to some of its measures could result in new laws and regulations promulgated by subsequent administrations which would prevent their realisation.

**As* Petroleum Review *went to press, BP's Thunder Horse platform was listing by about 20° after Hurrican Dennis passed through the Gulf of Mexico. The platform, located in Mississippi Canyon block 778, was evacuated prior to the storm. There are no reports of leaks.*

Canadian oil patch update

Henry Goodrich mobile offshore drilling unit drills wells for Terra Nova

Courtesy Petro-Canada

Judging from the amount of drill bits rotating in Canada these days, one might be forgiven for thinking that the oil and gas industry's favourite dance step is the twist, writes Gordon Cope. *According to the Petroleum Services Alliance of Canada (PSAC), an industry group representing service companies, the oil patch is on target to drill 23,825 wells in 2005 – a 5% increase over last year's record 22,600 wells.*

This frenetic activity has been fuelled by strong energy prices, which averaged \$41.40/b for WTI and \$6.03/mn BTu at Henry Hub through 2004. Oil companies are trying frantically to spend their revenues – overall, capital spending in drilling, producing and oil sands increased 11%, up from C\$28bn in 2003 to C\$31bn in 2004, and is expected to achieve approximately C\$35bn in 2005. Despite this, coffers have been bulging – the *Daily Oil Bulletin's* survey of 127 of the largest Canadian producers showed 2004 profits of \$16.6bn, up from \$15.9bn in 2003.

However, amid the seemingly endless good times, the Canadian oil patch is also experiencing its fair share of lawsuits, blow-ups and wrangles. Is too much success causing the sector to stumble sideways?

Blockage in the pipeline

The C\$7bn Mackenzie gas project seeks to connect 6tn cf of Arctic reserves to the existing North American natural gas network through a 1,300-km pipeline running down the pristine Mackenzie River valley. First gas from the 1.2bn cf/d line is supposed to arrive in Alberta by 2010. Or, that was the plan.

The project proponents – Imperial Oil, Inuvik's Aboriginal Pipeline Group, ConocoPhillips, Shell Canada and ExxonMobil – have already spent C\$350mn in advance of submitting it to a formal regulatory and environmental review, to be held sometime this autumn. However, as yet, the project has signed no access permits with the various aboriginal groups – several are using this opportunity to wring additional concessions from the federal government.

Fed up by delays, the consortium recently announced that engineering has been halted until the federal government steps up to the plate. 'There's a lack of firm political desire to reach a decision,' says Tom Ebbern, Managing Director of Research for Tristone Capital, an investment banking firm specialising in the oil and gas industry. While the analyst does not think that the deal will be indefinitely postponed, as some fear, he comments that 'they can easily lose a year or two'.

The competing Alaska gas pipeline is also facing problems. Enbridge, owner of Canada's largest pipeline system, has asked the federal government to override the National Pipeline Act – which was put in place in 1978 to regulate the Canadian portion of the Alaska Natural Gas pipeline – and open up the \$20bn project to competition.

TransCanada, which currently holds all certificates of conveyance in Canada, is not amused. If left out of the project, Enbridge threatens to initiate court action.

Not all pipeline news wallows in litigatious gloom though. Enbridge recently announced a memorandum of understanding (MoU) with Chinese oil giant PetroChina regarding the proposed Gateway pipeline. The C\$2.5bn project would transport up to 400,000 b/d from the Edmonton area, westwards through the Rocky Mountains to the deepwater ports of either Prince Rupert or Kitimat. PetroChina would then transport 200,000 b/d to Asia – although definitive long-term agreements for the sale of crude have yet to be negotiated at the time of writing.

TransCanada, not to be outdone, has proposed a \$1.7bn oil pipeline project that would ship 400,000 b/d south to the US. The 3,000-km Keystone project, from Alberta to Illinois, would involve the conversion of 1,200 km of existing gas pipeline and the addition of 1,800 km of new 30-inch diameter line. Depending upon industry interest and regulatory process, the pipeline could be in operation by 2009.

Much of the pipeline fuss is being generated by a surge in the oil sands sector. Production hit 1mn b/d in 2004 and the region has 47 initiatives worth C$70bn either recently completed, under construction or scheduled to begin in the next two years. Some of these include:

- Syncrude, which finished 2004 with 238,000 b/d production, and is undergoing a C$7.8bn, Phase 3 expansion.
- Suncor, which produced 215,000 b/d in 2004, has received the go-ahead to expand its oil sands operation with a C$1.5bn refinery upgrader that will boost synthetic crude production to 330,000 b/d by 2008.
- AOSP (the Athabasca Oil Sands Project) increased output from 61,000 b/d in 2003 to 135,000 b/d in 2004. It reached a milestone in June, having produced 100mn barrels of bitumen since its launch in April 2003. Plans will increase mine production from 155,000 b/d to 300,000 b/d. Approval is expected in 2006.

We 'blowed it up good'

While much of the success of the oil sands has to do with its low exploration risk, there are other hazards involved:

- A fire at Suncor in January reduced production to approximately 137,000 b/d (no one was injured). It hopes to return to full production by 3Q2005 and plans to reach 260,000 b/d production by the end of 2005.
- Also in January, a hydrogen unit at Syncrude failed. It knocked 5mn barrels off 1Q2005 production, from 20mn to 15mn barrels.
- At AOSP, 4Q2004 production was down almost 30% to 110,000 b/d due to maintenance and repairs at the Muskeg River mine.

Although the above problems were short term, other, long-lasting dilemmas remain. Cost overruns, for instance, are a continuing headache. OPTI Canada and Nexen – currently building the Long Lake, in-situ SAGD (steam assisted gravity drainage) project that will see the conversion of 72,000 b/d of bitumen into 58,000 b/d of 39° API sweet, synthetic crude – are keeping a tight rein on expenses by ensuring that 80% of engineering work is done before modules are built. The $3.5bn project, scheduled for first production in 2007, remains on budget.

A second concern is the cost of natural gas. In-situ production through steam injection requires 1,000 cf of gas, and upgrading to synthetic oil requires between 300 and 700 cf of gas. When a strong Canadian dollar is added to higher gas prices, the Canadian Energy Research Institute (CERI) calculates that the price per barrel needed to cover costs and generate a 10% return has risen to $30, versus about $25 the previous year.

Snow pipeline – gas pipe at Ikhil gas plant in NWT

Coke gasification is increasingly seen as an alternative to natural gas. Waste petroleum coke is put into a high-temperature, high-pressure gasifier with steam and oxygen to create syngas (mostly carbon dioxide (CO_2) and hydrogen). The output can be used to upgrade bitumen into synthetic crude, or for cogenerating electricity and steam for SAGD. While the capital outlay is significant, operating costs are low, and it eliminates the need to purchase gas. OPTI and Nexen are using a version at Long Lake, while Suncor is engineering an $800mn unit for its Voyaguer upgrader. Atomic Energy of Canada is offering a more exotic alternative – a CANDU* reactor would shave 20% off input costs in the form of lower gas usage, and could be scaled to a 200,000 b/d SAGD project. Upfront capital costs are significant, but the reactor has the advantage of zero greenhouse gas output.

Assuming that such problems are overcome, CERI projects that various oil sands projects will produce 2.6mn b/d by 2015 and 3.7mn b/d by 2020.

Which is just as well, as conventional production is on the endangered species list. According to CAPP figures, light, medium and heavy crude finished 2004 at 1,409,000 b/d, down from 1,462,000 b/d in 2003. Much of this plunge can be attributed to temporary production interruptions at offshore facilities on the East Coast – but the decline of conventional light crude continues unabated in the Western Canadian Sedimentary Basin, down from 573,000 b/d in 2003 to 555,000 b/d in 2004.

A minor burp

After an almost 4% drop in production in 2003, to approximately 17bn cf/d, gas production has staged a comeback, rising to 17.4bn cf/d in 2004 and climbing to 17.6bn cf/d in the first half of 2005. Much of this increase is due to the addition of tight gas wells in north-east British Columbia. However, operating costs are rising, having more than doubled to 93 cents per mn cf in 2003, up from 45 cents 1999. CERI projects that conventional gas production in the Western Canada Sedimentary Basin will drop from its current level of above 16bn cf/d to around 5bn cf/d by 2025 as fields deplete.

Coal bed methane (CBM) and LNG are expected to make up part of the shortfall. 'CBM makes a lot of sense,' says Ebbern. 'It has a low decline rate, so it will add a lot of stability to production. But the average initial production is around 100mn cf/d, so it takes a lot of wells. It could eventually reach 10% of current production, maybe 1.7bn cf/d.' While 1.7bn cf/d would require something like 17,000 wells to achieve, 3,000 wells are planned for 2005 alone. Already this trend has had a positive impact, adding 6tn cf of proven reserves in 2004 (versus production of 4.87tn cf). Producers hope to avoid the environmental and social headaches experienced in the US through a better legislative structure in Canada.

LNG holds similar promise. Out of the half dozen potential regasification sites, two have already been approved – Canaport in New Brunswick and Bear Head in Nova Scotia. Anadarko's Bear Head is already under construction; the 1bn cf/d facility is expected to be shipping first gas to the north-east US market through the underutilised Maritimes & Northeast Pipeline by 2008. The National Energy Board expects LNG to account for 1.4bn cf/d by the next decade, or 7% of total gas supply.

Troubled waters

At first glance, the oil flowing from the Grand Banks of Newfoundland seems

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Strong growth on diverse asset base

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

With an enterprise value of approximately $44bn, EnCana is one of North America's leading natural gas producers, is among the largest holders of onshore North American gas and oil reserves and is a technical and cost leader in the in-situ recovery of oilsands bitumen.

EnCana claims to deliver predictable, reliable and profitable growth from its portfolio of long-life resource plays situated in Canada and the US. Contained in unconventional reservoirs, resource plays are large contiguous accumulations of hydrocarbons, located in thick or really extensive deposits, which typically have low geological and commercial development risk, low average decline rates and very long producing lives. The application of technology to unlock the huge resource potential of these plays typically results in continuous increases in production and reserves, while decreasing costs over multiple decades of resource play life, claims EnCana.

EnCana's diverse asset base means that it is not dependent on any one project or play, and can be disciplined in moving out assets that don't meet its stringent criteria of superior returns, growth and critical mass, or which are simply worth more to others. Since the majority of the company's production is sweet, dry natural gas, there is relatively little operational complexity. EnCana's assets are primarily North American based, with 87% of 2004 production located on this continent.

Key resource plays

At EnCana, key resource plays capture huge accumulations of hydrocarbons trapped in unconventional reservoirs. For natural gas this means they must be of a size that will enable ultimate recovery of greater than 1tn cf of reserves and to grow to more than 200mn cf/d of long-life production.

In 2004, the company's eight key natural gas resource plays together produced an average of 1,606mn cf/d, or 54% of its North American gas sales, and accounted for approximately 73% of its proved natural gas reserves at year end. In 2005, gas production from these eight key resource plays is expected to increase by 23% to about 1,980mn cf/d.

Last year, EnCana's two key crude oil resource plays together produced an average of approximately 47,700 b/d, or 34% of the company's North American oil sales. EnCana expects crude oil production from these two oil resource plays to increase by 30% to about 62,000 b/d in 2005.

Canadian operations

EnCana has an industry-leading land position in western Canada of approximately 22mn net acres, of which approximately 14mn net acres are undeveloped. The mineral rights on approximately one-third of this land is acreage owned in fee title by EnCana, which means that production is subject to a mineral tax that is generally less than the Crown royalty imposed on production from land where the government owns the mineral rights.

EnCana is currently focused on exploiting its four key gas resource plays – located at Greater Sierra and Cutbank Ridge in north-east British Columbia, with coalbed methane and shallow gas in southern Alberta. The company is also exploiting two crude oil key resource plays at Foster Creek and Pelican Lake in north-east Alberta.

Natural gas sales averaged 2,099mn cf/d in 2004 and are expected to increase to an average of between 2,200mn and 2,300mn cf/d in 2005. Crude oil and natural gas liquids sales averaged 153,831 b/d in 2004 and are expected to average between 135,000 and 155,000 b/d in 2005.

US activities

EnCana's US operations are focused on exploiting deep, tight, long-life, unconventional natural gas formations. In 2000, when EnCana first entered the US by acquiring an initial stake in the Jonah gas field, the company produced an average of approximately 75mn cf/d of

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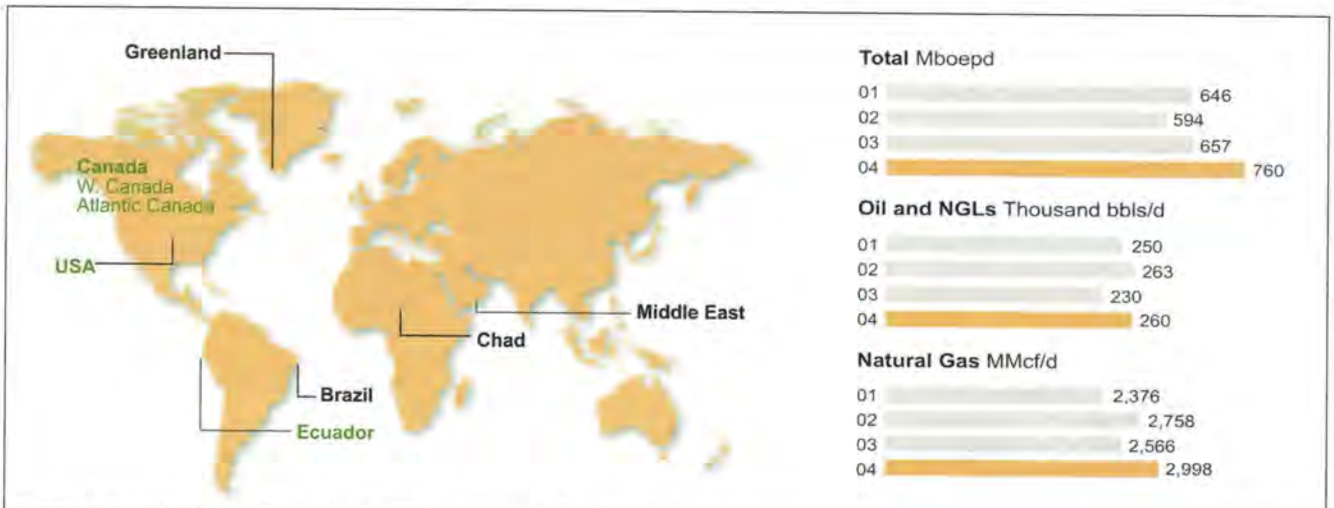

Figure 1: EnCana's core areas of E&P activity and 2004 (pro forma) production

Vessel equipment – key factor in hydrocarbon management

Photo: Bergesen

Shipboard measurements at the time of loading and discharging of petroleum cargoes form an integral part of hydrocarbon management. The quantities as determined by vessel measurements are not only significant for analysis and reconciliation purposes, but are also used fairly frequently as the basis for the bill of lading (BOL) or the official custody transfer quantity when availability of measurements elsewhere is limited or where contracts specify this approach. This article, by members of the Energy Institute's HMC-4B Oil Transportation Measurement Committee, *discusses some of the technical issues involved and provides recommendations which are aimed at assisting and improving the accuracy of measurement and sampling on ships.*

Bergesen's *Berge Stadt* oil tanker

Although ships are generally now equipped with automatic gauging and temperature measurement systems, independent certification of cargo quantity for contract and often government fiscal purposes must be carried out using third-party equipment (typically portable 'electronic' tapes/temperature instruments) provided and calibrated by independent inspection companies. It is also necessary to obtain samples from the cargo tanks, particularly prior to discharge. Although automatic in-line sampling equipment is becoming more widespread this is, of course, no use in alerting receivers to possible problems with the cargo before discharge.

The design of the cargo tanks and associated fittings and pipework can have a significant impact on the measurement and sampling process. This is particularly the case in recent years as environmental and safety concerns have resulted in measures designed to prevent the release of petroleum vapours to the atmosphere. These measures include the use of vapour control valves through which all instruments must pass to enter the tanks, providing challenges in obtaining accurate shipboard measurements – especially cargo samples.

Tank design

A conventional cargo tank consists of welded steel plates supported by an array of frames, webs, girders, stiffeners and brackets etc. Together, they form the integral strength of the vessel and are often referred to as 'deadwood' for measurement and calibration purposes. This deadwood can impede flow of liquid to the cargo pumps and prevent the COW (crude oil washing) jets from reaching certain areas of the tank.

All new tankers are now of double hull construction, where most of the structural components are located in non-cargo spaces outside the tank. These vessels, with their more regular, relatively unobstructed tanks, are already having an influence on measurements as noted by the EI HMC-4A Committee.*

Where there are obstructions within the cargo space, suitably sized holes should be provided through the structural members to allow for the free flow of liquid to the suction point. COW jets should be positioned to take account of these internal members so as to allow effective tank washing and to minimise any cargo remaining onboard.

On vessels that have double bottoms, it is preferable to have the cargo suction inlet located in a sump or deepwell. This again makes it easier to empty the tanks.

To allow the ship to be fully 'measured' in order to verify cargo volumes and transfers, other spaces need to be considered and treated in a similar manner to the cargo tanks.

Bunker tanks should be designed to allow for accurate measurement and sampling, with easy access for manual gauging and sampling equipment. The measurement points should be clearly marked on both the general arrangement plan and on the deck so that the correct readings can be taken for use with the calibration tables. The calibration tables should indicate the calibrated reference height.

Measurement points for ballast and engine room tanks should be clearly identified, showing the reference height, and these tanks should be readily accessible for gauging and sampling.

Void spaces are sometimes not calibrated, as they are not intended for the storage of liquid volumes. However, easy access to these tanks and spaces should be made available to allow checking by cargo inspectors.

Tank calibration

Cargo tanks should be calibrated by physical measurement rather than by calculations made from design drawings. In the case of new vessels, cargo tanks should be calibrated at the shipyard by an independent third party, using the best available technology, based on industry standards.

Any inaccuracy of the vessel calibration tables is often reflected in the vessel experience factor (VEF). The VEF is a ratio between vessel measurements and the corresponding shore measurements, calculated over many voyages. The manner in which vessel measurements are obtained, such as use of vessel automated tank gauging equip-

New technology tackles onboard VOC recovery

Some 100 tonnes of volatile organic compounds (VOC) vapour that would normally have been discharged to the atmosphere from the *Gemini Star* when it loaded crude oil, was instead retained in the cargo tanks during a recent trial of a new onboard vapour suppression system at the Ju'aymah loading terminal in Saudi Arabia on 11 June this year. *Brian Warshaw* reports.

The *Gemini Star* is a 280,000 dwt, single-hulled, very large crude carrier (VLCC) owned by Vela International Marine, a subsidiary of Saudi Aramco. The vessel was already equipped with a 100% VOC vapour cargo reabsorption system, supplied by the Norwegian company Venturie, to handle vapours created during a voyage. The new loading vapour suppression system was the second part of an integrated package.

In order to suppress the discharge of VOC vapours into the atmosphere, Venturie installed a back-pressure control unit and control valve on each of the vessel's two mast risers. Loading rates reaching as high as 80,000 barrels per hour were established with the pressure control equipment remaining fully functional. The back-pressure on the tanks in the case of the Arabian crude oil being loaded, and the vessel itself, was set at 1,200-mm water gauge – the typical pressure at which the cargo is discharged at the destination terminal. In current loading procedures, it is normal for the cargo tank to be at, or near, atmospheric pressure. The transmitter-controlled valves open and close quickly to keep the pressure in the cargo tank close to the designated set pressure.

Venturie has been a pioneer in the development of the system that uses back-pressure sensitivity on hydrocarbons in order to limit the evaporation of the oil – a system that has subsequently been adopted by Intertanko (the International Association of Independent Tanker Operators) in its VOCON guidelines, wherein the Association recommends a modest depressurisation when tanks have to be vented, rather than full pressure relief.

The original onboard vapour absorption system has been operating on the *Gemini Star*, and two other Vela-owned vessels, since 2002/2003. It, too, is a simple concept, using a double venturi gas compressor unit, a pressure transmitter and an oil pump, together with standard pipework.

How it works

During the voyage, as the pressure in the tank approaches the set-pressure of the valve, the absorption system starts to operate. The manufacturer claims that it requires no more than one to two hours operation daily to maintain the cargo tanks free of hydrocarbon vapours. Long-haul vessels carrying hydrocarbon products that have been stabilised require the system to be operated only a few times during the voyage, whereas those with unstabilised crude oil will require more frequent reabsorption.

Deckside installation of double venturi static gas compressor. Oil entry at top with side entry of vapour.

During the absorption process, oil is pumped from the bottom of the cargo tank and through the dual static venturi chambers. The venturi chambers pull in a mixture of VOC vapour and inert gas that has risen from the ullage volumes in the cargo tanks and into the ship's inert gas manifold. The vapour is changed into small bubbles that are readily absorbed into the oil and deposited at the bottom of the cargo tank. The pressure head of oil retains the absorbed VOC vapour, while the inert gas gradually rises to the top of the tank.

Sven Haggensen, Venturie's Principal Engineer who was present during the system installation, said that the investment in both systems will be repaid within the first year of operation, through the retention and recovery of the crude oil. He says that operating costs are low in power consumption, the units are almost maintenance free, and no special training is required for the crew.

In 2002 Vela stated that it was its intention to equip all its crude oil tankers with onboard vapour recovery systems. If the policy is carried through it will enable Saudi Aramco – which last year transported in excess of 1bn barrels of crude oil and refined products to destinations throughout the world – to achieve a place at the forefront of organisations observing the Gothenburg Protocol on VOC emissions.

ment versus manual gauging, or old calibration tables versus new tables, can have an affect on the repeatability and reliability of the VEF. The vessel should make every reasonable effort to accurately record data based on consistent gauging and calculation processes to assist in minimising the variability of the VEF. The new standard for calculation and application of VEF (API 17.9, EI HM49) should be issued later this year and provides detailed guidance for vessel owners.

Gauging points

The manual and automatic gauge points should be sited together (to allow for verification of the automatic systems) and as close to the geometric centre of the tank as possible in order to reduce the affects of trim and list. If a vessel is fitted with fixed gauge tubes below deck, these should be perforated to allow for equalisation of the liquid level and vapour pressure in the ullage space.

Any vessel that is capable of COW is required by the IMO (International Maritime Organisation) COW specifications to have four gauging points on each tank, with one position being at the aftermost portion of the tank. The provision of additional gauging points is not a requirement on product tankers or barges. However, the API recommends that there should be at least two calibrated gauging positions on each tank. If the vessel normally operates trimmed by the head or by the stern, gauge points should be in the forward and after portion of the tank. If the vessel generally trims by the stern, the central gauging position can be one of the two calibrated gauging points.

Any gauging point chosen by the vessel designer or operator should be placed to ensure that there are not obstructions beneath the gauging position with the vessel upright or in extreme trim or list conditions. With the vessel at any stage of trim or list, each point should be capable of being used to determine OBQ/ROB (preload onboard quantity/remaining onboard) or free water depth.

If the gauging point has been repaired, modified or repositioned, it may be necessary to apply offset corrections to the level measured in order to obtain the correct volume from the vessel's calibration tables. While this is acceptable, ideally a new set of tank calibration tables should be prepared.

It is recommended that on newbuildings both the automatic gauge and manual gauging system have the same zero point.


The *Maersk Pride* product tanker at sea

Photo: AP Moller/Maersk

Official gauge points should be clearly indicated and permanently marked with the reference gauge height, coinciding with the calibration tables.

Vapour control valves

Manual sampling is the primary way of determining cargo quality, and it is therefore very important that the vapour control valves are of sufficient diameter to allow access to the cargo for sampling equipment. The recommended size of vapour control valves is 100 mm (4 inches) nominal diameter. A 100-mm valve will allow access for the various types of sampling equipment which may be required depending on the cargo and sample type required.

Vapour control valves smaller than 100 mm in diameter (especially 50-mm (2-inch) valves) severely limit the type of equipment that can be used and, ultimately, the quality of the sample. Vapour control valves smaller than 100 mm do not usually allow for a detachable primary container (can or bottle) to pass through, thus requiring that the same primary container be used for multiple samples. As it is not practical to clean the equipment in the field between each use, the possibility for contamination of a sample from the residue of a previous sample is high. Also, in the case of volatility samples, decanting in the field is contrary to the requirements of the standard.

It is recognised that there is a cost implication associated with installing 100-mm vapour control valves (versus something smaller). However, it would seem that the long-term savings associated with reduced sampling times and better sample quality should outweigh the marginal cost increase for larger valves at the time of construction.

Piping configuration

There are numerous types of piping arrangements and almost as many variations in systems as there are ships themselves. Some are relatively simple and others are very complex, depending upon the type and variety of cargoes that the vessel was designed to carry and the level of flexibility and sophistication provided.

Optimum cargo handling would allow no more that one grade per segregated pump system. When multiple grades are carried, crossover valves may be utilised for interconnection of systems and it is here that cargo contamination is most likely to occur.

Main cargo lines on some older vessels have loops and rises that do not allow for complete draining. All cargo lines should be capable of complete draining to avoid any liquid becoming trapped and unaccounted for, and which could lead to possible cargo contamination. Cargo piping should be capable of draining into a dedicated cargo tank for each cargo system. This will ensure accurate accounting of accumulated liquids.

Stripping is the removal of the final small amounts of cargo, generally using smaller diameter pipelines/pumps. Many vessels are designed with a 'combination' cargo discharge system, where the cargo stripping line branches off the main cargo suction as opposed to a completely separate system. Vessels with this combined design are likely to lose suction sooner, potentially leaving a greater amount of cargo remaining onboard. Completely separate small diameter cargo stripping systems are recommended to better transfer and/or discharge all possible liquids from each cargo tank. In order to minimise any risk of cross-contamination between grades, a separate stripping line system for each cargo tank group is preferred. The main cargo suction line, as well as the stripping line location, should be in a sump, deepwell or at the lowest point of each vessel tank.

Heating coils

The positioning of heating coils can affect the efficiency of pumping and, more specifically, final stripping of high viscosity and high pour point cargoes. Heating coils should be spaced evenly over the bottom of the tank and preferably within 75 mm to 100 mm of the tank floor.

Automatic gauging

As noted in the introduction, even though there may be a fully operational automatic gauging system on a vessel, it is not the primary measurement standard. When automatic gauging systems are installed for custody transfer purposes, the accuracy of the system must be capable of being verified by manual methods, in accordance with international standards.

Temperature

Temperature is one of the most critical measurements for custody transfer. Whether fixed or portable electronic equipment is utilised for obtaining cargo temperatures, the equipment must be capable of being verified by manual methods and it must be able to obtain temperature readings at levels throughout the tank, in accordance with international standards.

Vessel attitude

After loading/before discharging, when the tanks are nearly full, the preferred attitude of the vessel is to be on even keel (ie with zero trim and list). This eliminates the need for any correction to be applied to the observed gauge readings. However, it is inevitable that in some circumstances the vessel will not be on an even keel and even a slight trim or list will necessitate the application of corrections.

The preferred method for determining trim/list of a vessel would be through observation of the vessel's draft marks. It is recognised that accurate observation of draft marks may not always be possible and it is therefore essential that vessels be equipped with suitable equipment to accurately determine the trim and list.

In general, it seems that there has been a lack of consideration given to the accurate determination of trim and list. Use of modern electronic devices could significantly improve cargo measurement accuracy by giving more accurate trim and list measurements and providing the ability to average readings to account for vessel movement.

Cargo vapour pressures

During the voyage, natural evaporation from liquid hydrocarbon cargoes causes the vapour or inert gas pressure above the cargo to rise. To avoid possible damage to the tanks it is standard practice to release this pressure to the atmosphere from time to time by manual opening of the mast riser valves. The vapour and inert gas is released until the pressure falls to some arbitrary low level.

The HMC-4 Committee believes that controlled venting at sea can reduce overall emissions and potential cargo loss. Traditionally, regular venting to a low pressure was thought to be the most effective method of tank pressure control. Recent studies have indicated that reducing to such low pressures can simply result in rapid evolution of more vapour and an accelerated pressure increase. Controlled venting to maintain a higher, but safe, pressure could significantly reduce total emissions. There are automatic venting valves available, which precisely and reliably maintain tank pressures. These valves can be set to open and close within a narrow range of pressures, essentially maintaining a constant tank pressure, thus removing the need for manual venting and reducing emissions.

A new generation of onboard vapour recovery systems has been developed and is currently being tested on some vessels. These systems are designed to eliminate the need for venting and return vapour to the vessel's cargo tanks, reabsorbed into a circulated liquid stream. However, further analysis of the effectiveness of these systems is required before a recommendation to install such equipment can be made.

It should be noted that recent regulatory activity, at both individual national and international levels, targets the elimination of emissions from tank vessels and may lead to requirements for the installation of such systems in the future.

**'Marine crude oil transport – 2003 Analysis'*, Petroleum Review, *October 2004*

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to cast a calming effect upon the stormy Atlantic region.

Hibernia, with 865mn barrels of recoverable oil, produces approximately 230,000 b/d. Terra Nova, with 353mn barrels, has the capacity to produce 133,800 b/d. And White Rose, when it comes onstream in early 2006, will eventually reach 92,000 b/d. The three fields, located approximately 300 km south-east of St Johns, will be responsible for more than half of Canada's conventional oil production. In addition, Chevron Canada is gathering up to 8,000 km of 3D seismic in the Orphan basin, while ConocoPhillips is planning to collect up to 6,100 km of 2D seismic in the Laurentian sub-basin between Newfoundland and Nova Scotia.

However, dip beneath the surface, and all is not well. Maintenance and regulatory problems (an oil spill) at Terra Nova reduced output in 2004 to 110,000 b/d. The Newfoundland government is also making sufficient noises regarding its royalty structure to make companies nervous. But hardest of all is the fact that no new major discoveries have been made recently. 'It's dying a slow death, there's been no major discovery for quite some time,' comments Ebbern. 'You have to go back a long way, to White Rose [1984]. Exploration activity has been cut back. A string of dry holes has chased people away for a while.' Until someone once again makes a major discovery off the East Coast, oil companies with a penchant for elephants will go hunting further afield. 'There are richer basins where the success rate is significantly higher – West Africa, Trinidad, the Gulf of Mexico.'

Refining sector

Refineries in Canada are not achieving the peak margins of C20 cents/litre (c/l) achieved in 2004, but returns are still better than the dismal state seen over the last decade. 'The sector is healthy and robust,' states Michael Ervin, President of MJ Ervin & Associates, a fuel consultancy. 'This year, margins have been peaking at 11 to 12 c/l. It only takes a penny a litre more for a really good year.'

The sector continues to consolidate, however. Thanks to regulations that require the reduction of sulphur in fuel, Petro-Canada closed its Oakville refinery in southern Ontario because it did not make economic sense to retool the facility for new sulphur limits on fuel. 'Oakville was a hit to refining capacity [currently in the neighbourhood of 3mn b/d], but it's been mitigated by the reversal of the products pipe to flow west from Montreal, creating more capacity for imported gasoline,' notes Ervin.

Overall, Ervin says the outlook for the refining sector remains positive. 'Demand is going to remain strong over the upcoming one- to five-year period. Utilisation rates in Canada and the US are certainly going to stay above 90%, and that indicates more upside than downside.' While there is no talk of new refineries, 'there will be de-bottlenecking and improving downstream processing capacity, which will increase the ability to manipulate outputs to meet demand profile,' says Ervin.

In conclusion, while some clouds gather on the horizon, the future generally looks bright. 'We've had a shortage of labour in Canada for the last few years, and we only see the situation getting worse this decade as the Boomer bubble works through the system,' says Roger Soucy, President of PSAC. 'But as long as the commodity prices remain above $40 for WTI and $4 or more for natural gas, you'll see continued high activity in Canada.'

**CANDU stands for 'CANada Deuterium Uranium'. It is a Canadian-designed power reactor of PHWR type (pressurised heavy water reactor) that uses heavy water (deuterium oxide) for moderator and coolant, and natural uranium for fuel.*

See you in court?

A company will always try to control where it litigates as part of its risk management strategy. The decision of the European Court of Justice in March 2005 in Owusu v Jackson* *has deprived companies of a significant area of control and has serious implications for a company's risk management strategy, as* Bina Shah, *Head of Litigation Know-How at Allen & Overy explains.*

Multinational companies incorporated in England but with subsidiaries and operations all over the world attempt to control the jurisdictions in which they might have to litigate by expressly choosing the forum and dispute resolution method in relationships governed by contract. But what about non-contractual relationships? What if there is an explosion in a refinery in Zambia, injuring not only employees but also innocent bystanders? Can the parent company be sued in England in connection with a tort in Zambia?

The doctrine of *forum non conveniens* – which is usually inelegantly translated into 'inconvenient forum' – is a flexible doctrine that allows the English courts to refuse jurisdiction if they consider that they are not the most convenient forum for the hearing of a dispute. The natural forum could be considered to lie in another country because, for example, the accident took place there or all the documents and witnesses are located in that jurisdiction. It thus effectively allows English companies to bat away litigation involving foreign torts

Note however, that prior to the *Owusu* case, it was only possible to use this doctrine if the two competing jurisdictions were England and a non-EU member state, such as Zambia. If the explosion had taken place at a refinery in Germany, the Brussels Regulation which sets out a strict scheme of rules to determine which country has jurisdiction would apply. The bedrock jurisdictional rule of the Regulation, which applies throughout the EU, is that a party can always be sued in the state in which it is domiciled unless the Regulation provides an exception (Article 2). If the two competing jurisdictions were EU member states, *forum non conveniens* had no role to play. Unfortunately, the *Owusu* case has clipped the wings of the English courts to use this doctrine in cases involving non-EU member states.

Case specifics

In this case, the two competing jurisdictions were Jamaica and England. In 1997 Mr Owusu suffered a serious diving accident while on holiday in Jamaica, which left him a tetraplegic. Following the accident, Mr Owusu brought proceedings in the English courts against Mr Jackson who, crucially, was also domiciled in England and from whom he had rented his holiday villa in Jamaica. He also brought an action in tort against several Jamaican companies. The defendants argued that the English proceedings should be stayed because the case had closer links with Jamaica and that, accordingly, the Jamaican courts were the most appropriate forum.

The Court of Appeal referred the question of the application of the doctrine of *forum non conveniens* in favour of the court of a non-EU state (in this case Jamaica), where one of the defendants was domiciled in a contracting state (here, England) to the European Court of Justice (ECJ).

The ECJ held that jurisdiction conferred by Article 2 was mandatory in nature. Where a party domiciled in England was sued in England, Article 2 required the English courts to determine the matter. The court could not exercise a discretion to decline jurisdiction on grounds of *forum non conveniens*. There could be no derogation from this rule except in cases expressly provided for by the Regulation. The Regulation provided for no exception on the basis of *forum non conveniens*, which is only recognised in a limited number of EU states.

Potential impact

The problems that this judgment poses are enormous. It leaves multinational corporations with their headquarters in England in the invidious position of potentially being sued here in respect of its activities anywhere in the world. The corporation is forced to defend these proceedings even though the only connection with England is the fact that it, amongst many other defendants, is the only defendant domiciled in England.

The time and cost implications of this are serious. Legal Aid may be available to the claimants, the legal costs of litigation are enormous and there is the reputational risk to consider. Companies will need to be aggressive in policing the activities of their overseas subsidiaries.

Somewhat tantalisingly the ECJ had declined to answer the wider, and much more relevant, question of whether the Regulation precluded the application of *forum non conveniens* in **all** circumstances on the grounds that this was a 'hypothetical' question. It left the issue whether a fragmented power to stay proceedings still existed unclear.

However, a glimmer of hope is provided by the robust first instance judgment in *Konkola Copper Mines Plc v Coromin***, where the judge held that if a defendant is domiciled in an EU state a jurisdiction clause conferring jurisdiction on the courts of a non-EU state is effective and will override the domicile rule in Article 2.

**Case C-281/02[2005] All ER(D)47 (Mar)*
***[2005] EWHC898 (Comm)*

Halliburton's real time operations centre in Calgary

Photo: Halliburton

Squeeze the rock

An energy hungry world wants more oil. One way is to find it with the drill bit. The other way is to use technology to increase recovery of what's already been found. But, as Petroleum Review *discovers, some schemes are better than others.*

Contrary to popular belief, the world has a lot of oil. The Energy Information Administration's (EIA), latest proven reserves show 1.1tn barrels of recoverable conventional oil (exclusive of oil sands).

The rub, of course, is that most of it – some 730bn barrels – is in the Middle East. To make matters worse, many non-Opec basins, such as the North Sea, are in decline. As consumption increases and excess production capability grows smaller, consuming countries in North America and Europe are understandably worried that production will become increasingly concentrated in politically unstable regions.

One candle of hope lies within the very nature of reserves. Most reservoirs give up only a small portion of their contents, some just 20%, under natural production methods. However, experts believe that recovery for many reservoirs can be increased to 60% – a tremendous boon. Of course, there are a few glitches.

At your MRC

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

MRC wells require complex technologies, such as geosteering and downhole valve control. If done correctly, they can tap into bypassed reserves and boost production. In the last few years, Saudi Aramco has been a champion of MRC wells. At its Shaybah field, a conventional horizontal well produces 2,000 b/d; an MRC well produced 12,000 b/d.

However, critics say that some reservoirs are unsuited to MRC and can be ruined – they point to the Yibal field in Oman, which initially improved production in the early 1990s after horizontal wells were introduced, but eventually watered out and production collapsed. Proponents say subsequent advances in the technology and analysis of reservoirs have corrected earlier problems... but the jury is still out.

In the driver's seat

Geosteering isn't applicable only to MRC wells, it can be used to great effect in a wide variety of circumstances. The concept is simple – real-time data is gathered as the drill bit advances, it is then transmitted back to an operations centre where, using 3D tools, engineers and geoscientists can visualise, analyse and interpret the information, they then send back commands directly to the drill bit or completion tool.

The North Sea, a high-risk, high reward venue, used to be the principal market for geosteering. However, land use is becoming more and more common. Marty Paulk, Real-Time Drilling Applications Manager for Sperry-Sun, estimates that, in 2005, the technique will be used for about 50 deepwater wells globally, but also for approximately 75 onshore wells in the Middle East and 75 wells onshore Canada.

Canadian Natural Resources Limited (CNRL) is using the technique to exploit its heavy oil deposits in northern Alberta. The deposits are being developed using cyclic steam stimulation (CSS), in which horizontal wells are drilled from pads into the reservoir, then steam is injected into the low viscosity petroleum until it is sufficiently mobile to be drawn to the surface.

CSS in heavy oil works best when the horizontal well lies as close to the bottom of the reservoir as possible. CNRL's reservoir consists of saturated sands sitting on top of a layer of shale. Before the company adopted geosteering, in order to identify the bottom of the reservoir, drillers would periodically dip the drill bit into the lower shale layer. This created unproductive lengths of borehole, and occasionally resulted in the bit getting stuck. And even when the bit remained in the reservoir, there was uncertainty as to its whereabouts. 'We had an elliptical error of +/– 7 metres,' says Carmen Lee, a CNRL Geologist. 'In a reservoir 15 metres thick, that's a lot of error.'

CNRL teamed up with Halliburton's geosteering technology. The cost for each well is in the range of $25,000 to $30,000, but the results are dramatic. 'The biggest upside is being able to consistently find the bottom of the reservoir,' comments Lee. 'In the past, you might capture only 7 metres of a 10-metre reservoir. Now, you capture the full 10. That means a 10% to 30% increase in recovery. That alone will pay off the investment.'

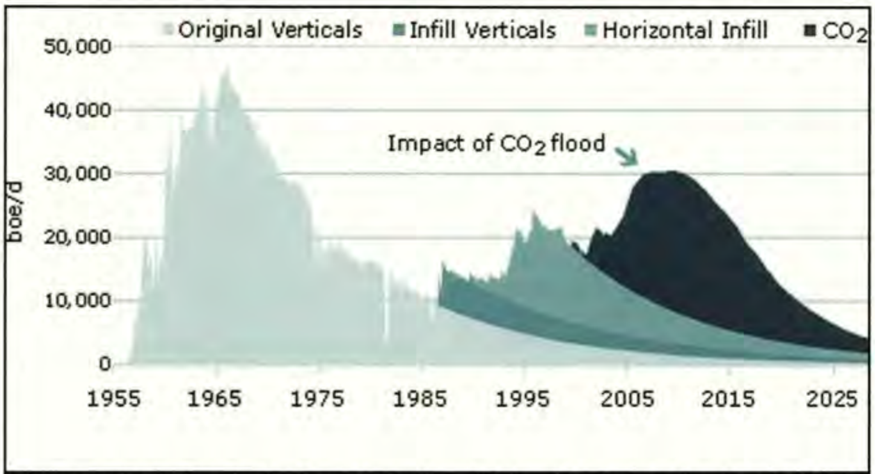

Figure 1: Historical production from the Weyburn field, and the impact of carbon dioxide (CO_2) flood *Courtesy EnCana*

Cracking up

Once a well is drilled, the amount of oil or gas produced is primarily dependent upon its conductivity, the amount of hydrocarbon that flows to the wellbore. Increasingly, companies are artificially increasing the conductivity through the use of fracturing.

In order to fracture a reservoir, fluid is pumped down the wellbore and into the consolidated formation at pressures sufficient to overcome its internal strength. Proppant (commonly sand) is added to the fluid and allowed to settle in the fracture to ensure that it remains open after the pumping has stopped. The goal of fracturing a reservoir is to create a narrow, long crack in the formation rock to serve as a flow channel to the wellbore. Fracturing the formation increases the conductivity by several orders of magnitude. This allows a faster return on capital investment and ensures that the well produces more.

In the Middle East, Saudi Aramco is experimenting with a combination of fracturing, acid stimulation and horizontal drilling to boost production of its AKF oil fields. It is in North America, however, that the trend has really taken off. 'Around 80% of wells drilled in North America are gas wells – about 24,000 wells,' notes Greg Salerno, Drilling Manager for BJ Services. 'About 80% of those are fractured – around 20,000 wells.'

The major market for fracturing is currently in thick, low permeability sands that require special attention in order to create and maintain conductivity. EnCana is using the technique in north-east British Columbia and the Rocky Mountains to tap into several tn cf of otherwise unproducible gas. Fracturing is also key to exploiting coal bed methane (CBM), a resource with huge potential in North America. Companies will drill and stimulate 3,000 CBM wells in Canada this year alone. The eventual goal is to replace 10% of Canada's gas production, currently above 16bn cf/d, with CBM gas.

Water floods

As previously noted, initial recovery from a conventional oil field can be in the order of 20%. For the last few decades, producers have been using water floods on selected fields in which injector wells are primed with water in order to push bypassed oil toward the producing wells. 'You can recover a further 5% to 20% with water flood,' says Bruce Peachey, a Production Engineer Consultant. However, water floods have a weakness that tends to make producers shun such schemes – the pressurised water can follow a high permeability streak and burst right through to the oil well, creating a bigger headache than if nothing had been done at all.

In fact, whether a water flood is being used or not, water production is a big problem in any mature region. Canadian fields produce more than 11 barrels of water for each barrel of oil, and the figure is expected to escalate to the same situation as experienced in Texas, where the ratio is around 20:1. Eventually, of course, the cost and nui-

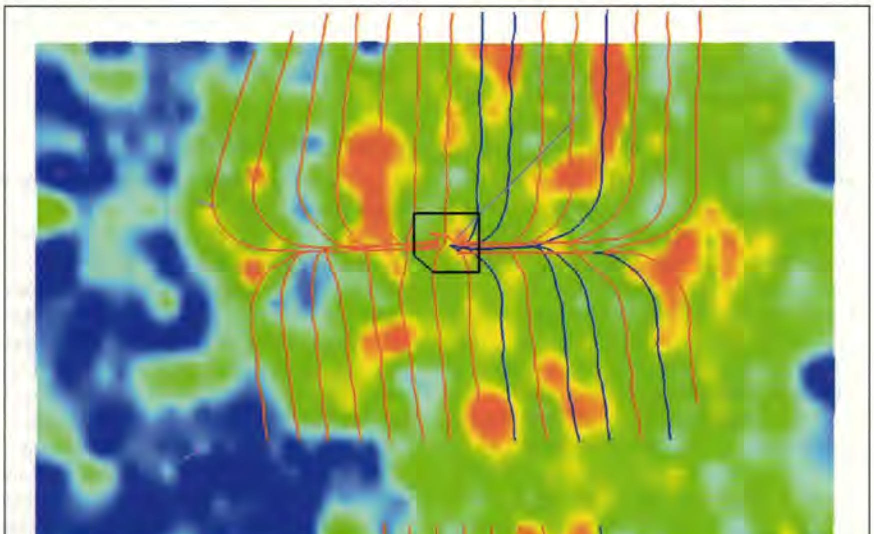

Figure 2: 4D seismic showing the dispersion of steam around the pad – hottest in red *Courtesy Shell Canada*

sance of getting rid of waste water becomes prohibitively expensive, and companies abandon fields when they are still mostly full of oil.

Service companies have come up with several innovations to control water cut. Halliburton offers a polymer that is injected between the oil/water line so that water cannot 'cone', or be sucked upwards. 'It forms a low permeability ring around the wellbore at a distance of 20 ft so that water cannot get sucked up into the oil zone,' explains John Warren, a Product Manager for Halliburton. 'We've had a 90% to 92% success range for shut-off of water. In wells we've applied this to, there's been a 10% to 15% minimum increase in recoverable reserves, and it's risen up to two-fold.'

In addition, other chemicals have been devised to control breakthrough in water floods. The polymers expand in the presence of water, shutting off the pore throats, but remain benign in the presence of oil and gas, thus preferentially controlling water movement. 'If you can achieve a 1% increase in recovery for mature assets in North America, you can add a billion barrels of improved recovery,' says Warren.

It's a gas

A few producers are also subjecting their fields to a secondary form of EOR (enhanced oil recovery), known as gas floods. Carbon dioxide (CO_2) or nitrogen (N) is injected, either at low pressure, where it acts as a pressure front to drive bypassed oil to the producing well, or at high pressure, where it mixes with the oil (miscible flood) and reduces the viscosity, making it easier to move to the producing well. 'You can recover a further 5% to 30% with gas injection,' says Peachey. Gas floods have been used in a wide array of locations, including the North Sea, but they are mostly to be found in Texas, where a huge, indigenous supply of CO_2 in New Mexico supplies cheap gas.

EnCana's Weyburn field in Saskatchewan is a textbook example of the value of gas flooding. Discovered in 1954, the 1.4bn barrel field has been on water flood since 1964 (increasing its recovery rate to 30%) and has been on CO_2 miscible flood since 2000. The gas flood will boost recovery to 46% – an additional 220mn barrels. (See **Figure 1**.)

However, gas floods are relatively few and far between, and are likely to stay that way. 'What limits gas EOR is a supply of cheap CO_2,' notes Jeff Wojahn, Executive Vice President of EnCana. 'There's no clean, indigenous source like the multi tn cf deposit in New Mexico.' There are also economies of scale – the infrastructure costs for gas flooding mean that only the largest fields qualify. 'West Pembina is also using CO_2 EOR, but it's a 1bn barrel field,' comment Wojahn.

4D seismic

One shortcoming with any enhanced recovery scheme is measuring its outcome. Companies are now using 4D seismic to measure what was previously invisible. 4D seismic is similar to 3D seismic, in that lines are closely spaced,

UK plans to capture carbon dioxide

A pioneering plan to tackle climate change by capturing carbon dioxide (CO_2) from power plants and storing it safely in depleted North Sea oil and gas fields was recently outlined by UK Energy Minister Malcolm Wicks. Carbon capture and storage could be up and running within a decade and is central to a new £40mn package for emerging low-carbon technologies designed to stimulate demonstration projects for cleaner electricity generation from coal and gas as well as for hydrogen and fuel cells.

Speaking in the run up to July's Gleneagles G8 Summit, at which the Prime Minister put climate change centre stage, Wicks said: 'Reaching our ambitious target of cutting carbon emissions by 60% by 2050 means action now to support emerging technologies that will enable us to burn coal and gas more cleanly. At the same time, with major expansion of coal-fired power generation expected in China and India, we want to put the UK at the forefront of what could be a valuable new export opportunity.'

'We've consulted the industry closely and it's clear that the long-term benefits of capture and storage, which could reduce emissions from power plants by up to 85%, merit significant investment now. We must, of course, maintain the push toward renewables and energy efficiency that deliver cuts in emissions here and now. But cleaning up our use of fossil fuels, developing the vast potential of hydrogen and fuel cells, and keeping UK industry on the front foot is a vital long-term objective.'

The Carbon Abatement Technology Strategy is worth £25mn. It will advance all forms of carbon abatement technologies, including improving the efficiency and co-firing of existing power plants with low carbon alternatives such as biomass, but the demonstration of carbon capture and storage is the most radical of the options and sets the new strategy apart from the previous Clean Coal Technology programme.

Barriers remain

However, according to the UK Offshore Operators Association (UKOOA), a number of its members have already studied the feasibility of capturing or sequestering CO_2 emissions from onshore sources (such as power stations) and storing it in depleted oil and gas fields, and have found that there are 'considerable technical, regulatory and cost barriers still to be addressed, with economic and fiscal implications'.

'Sequestration is already practiced in the US on land, though it requires fiscal incentives to be attractive. Offshore in Norway in the Sleipner gas field, CO_2 is removed from the produced natural gas stream on the platform, to improve the natural gas quality, and is re-injected for permanent storage. Removal and reinjection of the CO_2 was an integral part of the field's overall development planning and economics, and the offshore production facilities were specifically designed for the purpose. In addition, reinjection at Sleipner is into a saline aquifer and not into the gas reservoir. BP has also begun a similar project in the Algerian desert,' notes UKOOA.

But it continues: 'Capturing CO_2 from an onshore location and transporting it offshore for reinjection through existing oil and gas pipelines and installations is an entirely different and much more costly matter. In the North Sea it would require significant investment in new infrastructure both on and offshore, including substantial retrofitting of the offshore installations, where there are weight and space limitations.'

'A further hurdle is the legality of transferring carbon dioxide, officially designated a "waste" product, from one location to another for disposal offshore, which is not allowed under current international law (OSPAR and the London Convention).'

'Injecting CO_2 into fields could help recover more oil from maturing reservoirs, as in the US. However, not all oil fields are suitable candidates for this technique. The process of enhanced oil recovery (or EOR) is already practiced in various forms in the North Sea, so using CO_2 for EOR, where practicable, will only bring marginal benefit to the recovery of oil reserves.'

often only a few hundred feet apart, allowing for a much more detailed view of underground geology, including oil/water contacts in reservoirs. 4D has the added dimension of time, however. Geophysical crews return periodically and redo the original 3D survey using the same geophone and shot locations. This can show the movement of the oil/water contact as the reservoir is produced, allowing engineers to identify areas that are being left behind.

It turns out that 4D has a very important application for oil sands. Shell has been investing several billion dollars to exploit the Peace River oil sands deposit in northern Alberta. The deposits are too deep for mining; instead, they use cyclical steam stimulation. Using evenly spaced pads, as many as two-dozen horizontal wells are drilled in a regular pattern through the reservoir. During the first phase of Shell's operations, however, engineers began to notice that some wells were producing poorly, others not at all. The company decided to initiate a 4D seismic survey to figure out what was happening to the steam.

Shell discovered that the steam did not distribute itself evenly. Engineers are currently working out the best way to deal with the problem – shorter horizontals, vertical wells or downhole valves. 'It is allowing us to identify how we drill wells for the next 70 pads, over $1bn in expansion,' says Peter McGillivray, a Senior Geophysicist with Shell. 'We'll be able to drill and operate better; instead of 10% recovery, we might get 25% or 40%. The potential economic impact is enormous.' (See **Figure 2**.)

Digital oil fields

However, the biggest benefit of new technologies may arise from the use of real-time data to conceive, drill and produce a reservoir – the digital oil field (DOF). Three major areas of technological concentration are leading the DOF charge – visualisation centres (see headline photos), real-time drilling and intelligent wells. Visualisation centres allow the analysis and interpretation of large geological, geophysical and engineering databases. Real-time drilling permits engineers to steer the drill bit to the best reservoir locations, and intelligent wells use sensors and valve controls to allow companies to optimise production throughout the life of the field.

Several companies are conducting major DOF initiatives internationally. Perhaps the best-known facility currently operating is ConocoPhillips' Onshore Drilling Centre (ODC) in Stavanger, Norway. Costing approximately $6mn, the ODC began operations in 2002 and was soon overseeing drilling in the Norwegian sector of the North Sea. The ODC reduced the number of rig staff and drilling days and brought real-time control to field production. According to the company, it paid for itself in 10 months and achieved savings of around $12mn within the year.

Cambridge Energy Research Associates (CERA) has compiled a report entitled *The Digital Oilfield of the Future*. 'Advantages can be very field specific, but here are some general numbers,' says Bill Severns, author of the report. 'You can reduce operating costs by 4% to 10%. You can gain additional production of 4% to 10% from fields that have DOF versus those that don't. We've done a globally detailed assessment of additional reserves, and there are up to 125bn barrels of incremental reserves that could emerge over the next 10 or so years.'

And that makes oil companies very happy. 'We look at the best value proposition,' says EnCana's Jeff Wojahn. 'If we can get it through EOR (or any appropriate technology), we do that.'

...continued from p22

natural gas. In 2004, average natural gas production was 869mn cf/d, a more than 11-fold increase.

Essentially, all of EnCana's US natural gas production is sourced from resource plays. The acquisition of Tom Brown in May 2004 significantly expanded opportunities within existing operating areas while adding new resource play areas.

The company is currently focused on exploiting four key natural gas resource plays at Jonah and the Piceance in the US Rockies and in the Fort Worth and East Texas basins in the state of Texas. Together, these four key resource plays accounted for approximately 80% of EnCana's total US gas production in 4Q2004.

Natural gas production averaged 869mn cf/d in 2004 and is expected to increase to an average of between 1,150mn and 1,200mn cf/d in 2005.

Overseas business

Through its indirect, wholly-owned subsidiaries, EnCana is the largest private-sector oil producer in Ecuador, with net daily production, after royalties, of 76,872 b/d recorded in 2004. The company's interests in Ecuador also include an indirect equity interest in the OCP pipeline – a 500-km pipeline with a capacity of approximately 450,000 b/d that runs from the crude oil producing area of Ecuador to the Pacific Ocean.

In late 2004, however, EnCana's Ecuador operations were deemed to be non-core and the company plans to dispose of these assets in 2005.

Looking elsewhere, EnCana's new ventures exploration programmes are designed to provide large, conventional discovery upside. The company invests a small portion (approximately 2%) of its capital in high potential exploration beyond its core geographic areas – primarily in Canada's Frontier areas, Africa, Brazil, Greenland and the Middle East.

Asset sales

In May 2004, EnCana reached agreement to sell conventional oil and gas assets producing approximately 6,400 boe/d, after royalties, to StarPoint Energy Trust for approximately C$404mn ($326mn) before adjustments. The transaction includes properties in central and southern Alberta. Production from the assets is around 86% oil and natural gas liquids.

Since the start of 2004 and including this divestiture, EnCana has sold approximately 84,000 boe/d of conventional production, generating proceeds of about $6bn. The sale to StarPoint was EnCana's third substantial divestiture of Western Canadian conventional oil and gas assets and is part of the company's planned disposition of some 20,000 boe/d of Canadian conventional assets in 2005.

In 2Q2005 EnCana completed the sale of its Gulf of Mexico assets to Statoil for approximately $2bn, resulting in net proceeds of approximately $1.45bn after tax and other adjustments. The interests included six significant deepwater discoveries and an average 40% working interest in 239 gross blocks comprising about 1.4mn acres. At 31 December 2004, EnCana had 41mn boe of proved reserves booked at the most advanced of its Gulf of Mexico discoveries – Tahiti.

Earlier, in December 2004, EnCana closed the sale of its UK assets to Nexen for approximately $2.1bn. EnCana UK's interests included a 43.2% interest in the Buzzard oil field, a 41% stake in the Scott oil field and a 54.3% interest in the Telford oil field, plus interests in other satellite discoveries and exploration licences covering more than 740,000 net acres in the North Sea.

EnCana is now focusing on long-life North America resource plays where the company expects to achieve reliable, profitable growth in reserves and production from unconventional gas and oil reservoirs.

*Visit **www.oilvoice.com** to view a worldwide selection of continually updated oil company profiles, or contact Chris Pettit on e: **chris@oilvoice.com**

Continuing the great oil and gas adventure

Michel Contie *of Total E&P UK is this year's recipient of the Energy Institute's (EI) Cadman Memorial Award – one of the EI's most prestigious awards.* The Cadman Memorial Medal was presented to Contie at the Honourable Society of Lincoln's Inn, London, on 23 June 2005, after which he gave the traditional Cadman Lecture, a slightly shortened version of which follows.*

John Cadman was a truly remarkable man. He embodied so much of that spirit of adventure and of vision which remains the necessary template for oil industry success today, inspiring me to select the theme of this evening's lecture – 'Continuing the great oil and gas adventure'.

He rose from relatively humble origins by the force of his intellect and personality, coming in time to lead the development of one of the world's major oil companies during the late 1920s and 1930s. This was a quite extraordinary period of expansion, not to say drama and crisis, in the oil industry. The growth in the market for oil, together with the discovery of giant fields in Iran and Mesopotamia, had led to a rise in the strategic importance of the Middle East at the eve of the Second World War. It was also the birthplace of the Compagnie Francaise des Petroles, later to become Total.

One of his major contributions was in influencing the energy policy of the UK, in particular through his relations with Winston Churchill. In 1914, Cadman was a key member of an expert commission to Persia to assess oil field and refining capacity. The report's favourable findings led to Churchill's visionary decision to change the ships of the Royal Navy from coal to oil-burning. As a consequence, the government provided a substantial cash injection into Anglo Persian Oil (later BP) while simultaneously contracting it to supply the Admiralty with a large and secure supply of oil over the next 20 years.

His career then blossomed spectacularly. Appointed as Technical Advisor in 1921, he was Chairman of Anglo Persian Oil by 1927. His vision encompassed the strategic as well as social impact of oil on the modern world and the importance of the relation between the west and the Middle Eastern countries. This was demonstrated by one of his earliest statements as Chairman, when he said of Persia – where the company held important concessions: 'We want Persians to feel that our activities in Persia are not only directed to extracting oil but also towards developing a great national oil industry in the country'. Within six years, the Shah of Iran summarily cancelled Anglo Persian's concession. Cadman himself flew to Iran and persuaded the Shah to revive it.

Personal adventure

My adventures in the oil industry over almost 30 years have been characterised by many challenges, both technical and otherwise. My first contact with the industry was in 1973 – the year of the first oil shock. Within a few months of my joining the oil price escalated from \$10/b to \$35/b (2004 terms), with consequences that fundamentally changed the industry. Exploration was already well under way in the North Sea, and the industry was very actively seeking ways to reduce both cost and risk in what was the most difficult offshore provinces in the world. The European Economic Community had given its support to an ambitious project to drill and produce hydrocarbons in water depths of 1,000 metres. France, in line with its strategy to reduce energy dependence on imported oil, supported the programme, despite its very ambitious nuclear energy development.

Two years after the oil shock, Total drilled in the deep waters offshore the coast of Africa. As a young R&D engineer, I participated in this new frontier project and was soon involved in the development of floating production systems for deepwater, carrying out a test programme off the coast of southern California. Since the oil price was not yet quite high enough to justify deepwater developments at that time, I transferred to the Middle East where there was more action.

During more than four years as Manager of Total in Abu Dhabi between 1986 and 1991, the Middle East was shaken by three crises that involved several countries in the Gulf region. The most recent of these was the first Gulf War. All of them caused destruction to oil installations and created oil price instability.

EI President Sir John Collins (right) presents Michel Contie with the EI Cadman Memorial Medal

Nevertheless, thanks to the courage of those who continued their duties on the platforms and tankers across the Gulf region, oil continued to flow, with only limited interruptions of supplies.

By 1991, I brushed-up my Spanish to concentrate on the development of the new frontier area that was Latin America. Colombia was first. Here, the discovery of a huge oil field quickly rose to the top of the national agenda, precipitating fears of the 'Dutch disease' – ie inflation in the country's economy – and, also, the endemic civil unrest that spread out to the drilling sites and along the route of the oil pipeline under construction. These two elements and their consequence added another dimension to the already difficult challenge of drilling deep wells in the highly complex geology of the Colombian cordillera.

I was then active in the southern cone of the continent where Argentina, Brazil, Chile and others had decided at the time to liberalise their economies and to develop an integrated gas market. Here, we were facing the challenge of developing a totally new gas market in Santiago, Chile, a city hit by pollution and urgently needing gas to run its power stations and for residential use. There were two pipeline projects to transport the gas from Argentina across the Andes competing for this market. The group who took the risk of building the pipeline without yet having secured the gas contracts won the market. The pipeline, crossing the Andes at 4,500 metres, was laid in record time to avoid construction during the winter season.

Those who have experience of the energy developments will know that controlling the logistics is a key element of success. This is equally true today in projects like LNG regasification schemes.

By 1999 we had started drilling in jungle-covered Bolivian mountains, searching for gas in deeply buried reservoirs at 5,000 metres depth. The aim was to feed the Brazilian market, with its fantastic development of combined cycle power plants, and respond to the huge growth in electricity consumption in that country. As a result of opening up this new geological play, Bolivia's reserves were increased three-fold within a few years, quickly filling the capacity of the newly constructed 3,000-km pipeline between that country and the most populated areas of Brazil.

Simultaneously, 5,000 km further south in the island of Tierra del Fuego, we were drilling a world record well from onshore to an offshore target at close to 11,000 metres departure. This well opened the way to the development of a gas field using extended reach drilling and reduced cost and environmental impact by eliminating the need for a production platform offshore.

The same technique is now being used from an offshore platform to develop a gas field located 80 km from the coast of Tierra del Fuego. The Carina field, now the most southerly offshore field in the world, was inaugurated today [23 June 2005] by Argentinean President and the CEO of Total, Thierry Desmarest, almost 20 years after its discovery. It is an extreme example of the length of time required to put in production projects in areas remote from the markets, where technical challenges are compounded by difficult political and economic conditions.

Recent political change in South America, with a shift from liberalism to populism, has made the investment decisions needed to meet the demand for energy in this part of the world, all the more difficult to take.

These examples show the criticality, especially in the gas business, of aligning exploration, market access through adequate logistics and the right political and economic conditions. You can appreciate that this needs good analysis, good cooperation with host-governments and a fair amount of risk taking by investors across the value chain.

Continuing challenges

These examples show, just as in John Cadman's day, the adventure is continuing. Economic, political and technical challenge is a constant in our industry. And will it remain so, I think for two reasons.

First, I'm not sure that E&P will ever be completely mastered in terms of science or technology – despite all the improvements we have observed in past years, especially in seismic analysis. It is an activity that evolves continually. What is extraordinary one year is conventional the next. In this industry, 'adventure' is no exaggeration. Every day we take new risks – the stakes remain very high. 'Upsides' and 'downsides' are still the rule.

Second, because of the geopolitics where oil reserves are found, we are required to push the boundaries of what one can achieve in terms of relationships and management. This, too, requires an adventurous spirit. The two oils shocks of the 1970s changed the idyllic view of abundant energy, but at the same time stimulated dynamism and adaptability of the industry. By the end of the 1980s some of the old established companies were on the verge of bankruptcy, due to the loss of their production base following the forced nationalisation of their activities in Opec member countries. This meant that all the international oil companies that did not have access to important reserves in non-Opec countries were obliged to find quickly new areas in which to grow. It is this radical development that has really fostered the kind of flexible, dynamic approach to problem solving that is characteristic of the international oil companies (IOCs).

It is clear that matching global world energy requirements can be achieved technically more rapidly by investing in the known acreage of the large oil producing basins. Sustaining a convergence of interests between Opec, the IOCs and the consuming countries will be a continuous challenge in the coming years, adding to the geological adventure which will always remain despite better technology.

A necessary activity

In spite of what some organisations claim, oil and gas exploration and development is a very necessary activity. The requirement for hydrocarbons is very high and will remain so over the next decades – more than 1.5bn people have no access to electricity or clean water, the globalisation of economy is demanding more in terms of transport, and oil is required for just about all forms of transport.

Our industry is faced with the twin challenges of meeting the growth in global oil demand of approximately 1.5% per annum and countering the impact of decline from existing fields. Growing the reserve base by finding and developing new oil fields for the benefit of future generations is a tremendous challenge. Over the next ten years we will have to replace more than half of global oil production in order to meet the estimated requirement for new field production of 50mn b/d. This represents more than 14 times today's production levels from the UK North Sea! Finding and developing this level of resources is a task made all the more difficult by the fact that large-scale new reserves are now increasingly unconventional and difficult to access. Thus, it is necessary to be more and more inventive to find efficient ways to extract oil from tar inside rocks in locations like Canada and Venezuela, and to tackle the risks associated with drilling in deeper and deeper offshore locations.

The detractors of this industry will say that building our future on a source of energy dependent upon so many risky factors is not a reasonable option anymore. For that reason, I thought I would take this opportunity to share with you a few of my thoughts and those of my colleagues at Total on the conditions upon which our industry will be able to maintain the reliability of energy supplies.

New paradigm?

Having touched on the issue of increasing future oil demand, I would like to say a few words on the subject '*à la* *mode'* – the 'new paradigm for energy' (which seems a very theoretical, even philosophical word for a Frenchman to describe the energy markets!). However, I think that this grand term means simply that the oil price is presently much higher than it was in the 1990s and that it may stay at a high level for a few more years.

The current tension in oil prices is primarily attributable to the disappearance of surplus oil producing capacity. This is a result of faster than expected growth in global demand, coupled to uncertainty of non-Opec supply, which is in a global state of concern over potential supply disruptions from countries such as Iraq, Venezuela and Nigeria. In fact, the situation is not too dissimilar in the UK and US gas markets, where the growth of demand is not being matched by sufficiently large increases in domestic supply.

These tensions in the oil market have clearly occurred after a period of significant consolidation that created the main international oil companies we have today – ExxonMobil, BP, Shell, Total and Chevron, two headquartered in America and three in Europe. Each of these 'super majors' produces more than 2.5mn boe/d, and each is of a sufficient size to be a truly global operator. But this consolidation must not hide the fact that the super majors account for less than 16% of annual oil production and less than 10% of reserves, even though they account for almost 30% of annual capital expenditure. In that sense, the international oil companies have no market power. Rather, it is the national oil and gas companies that were created during the nationalisation of many parts of the industry in the mid-1970s that are the truly dominant players in the oil market. The majority of these national companies are from Opec member countries, and collectively manage more than 75% of conventional oil reserves. (See **Figure1**.)

As oil demand grew very strongly in 2004, Opec countries and, specifically, the Middle Eastern countries, increased their production in an effort to try to contain excessive price increases. To some extent, this effort tempered prices and prevented a repeat of the prices experienced in the 1970s. But it is clear that a build-up in spare production capacity is required in the short term, in order to create sufficient flexibility to face the vagaries of demand. This can most easily be achieved by investing more widely in the known acreage of the large oil basins, in particular the Middle East. Furthermore, it is absolutely necessary to bring about more significant cooperation between the international oil companies and the national companies of the large producing countries – bringing together joint technical expertise and know-how in leading complex projects.

As a result of falling production in OECD countries and other producing areas, oil is more and more likely to come from the Middle East. This concentration of production brings with it the risk of restricted access to new acreage. The willingness of Opec members to limit their production to preserve reserves for future generations could drive to a peak in oil supply at a level significantly lower than the 125mn b/d predicted by the International Energy Agency (IEA) – maybe much more like 115mn b/d – and sooner than the year 2030 forecast by the IEA. But this peak level should be much more like a plateau with a very low decline for a few decades – it would provide a period in which consumers adjust their consumption of oil (giving the priority of transportation) and producers develop alternative sources with new processes like gas-to-liquids.

The access to resources and, in particular, new acreage in the large producing countries, has appeared easier for natural gas than for oil. A company such as Total will see the relative proportion of gas in its production increase from 30% to 40% through the expansion of LNG.

In fact, while oil production should grow by around 40% in the next 20 years, natural gas should gain about 60%. The ratio of gas to oil will increase from 60% today to around 70% in 2025. The gain in LNG trade will be very strong, with a 6% annual growth. The world LNG market will become more and more global, mirroring the oil market and taking on a bigger role in heating use and power stations. Gas carries considerable environmental advantages too.

A positive impact of the strong oil price environment is to increase the life span of existing fields and improve the economic potential of small satellite fields offshore. The current price environment recreates, in the very deep offshore environment, the experience of the North Sea during the early 1990s. Having developed the very large accumulations, present price levels should allow medium-sized fields of the order of 100mn to 150mn barrels to be developed. The same principle also applies to the potential extension of recent extra heavy oil developments in Canada, Venezuela and other areas such as the Middle East, Asia (notably China), Russia and Africa – even though the heavy oil resources are smaller.

Maybe it is true that all these characteristics amount to a new paradigm. Certainly, a degree of uncertainty will remain for the short term at least, as the need to balance supply and demand results in volatile price levels.

Technological evolution

On the supply side, technology is and will remain the best tool we have to respond to the production challenge.

Exploration methods have progressed substantially over the years through advances in seismic imaging, resulting in greatly improved success rates. In terms of production technology, new advances are continually being made to improve hydrocarbon recovery rates. More detailed data combined with higher precision and extended-reach drilling allows reservoirs to be tapped at optimal locations, and the models used to simulate the production of reservoirs have been much improved due to advances in IT. In more mature fields, enhanced oil recovery projects (through water, natural gas or carbon dioxide injection) are also enabling more of the oil in place to be recovered. Good examples of the success of such techniques are the Ekofisk field in Norway and the Alwyn field in the UK sector of the North Sea.

The harsh environment of the North Sea has also acted as a significant learning ground for other technological advances that have made it possible to undertake E&P in deeper and deeper waters. Examples here include the Gulf of Guinea and the Gulf of Mexico, where production facilities such as the *Girassol* FPSO sit in waters exceeding 1,500 metres in depth.

New technological developments are also making the production of extra heavy oil in Canada and Venezuela economic, and a real source of potential oil supply for the long term. Techniques of cold production in Venezuela and mining extraction in Canada have been perfected, and costs have been reduced significantly such that the bitumen extracted is now price competitive with conventional output. In Canada, the production of 'in-situ' oil sands through steam injection is just starting up and the results of a number of pilot projects that have just come into operation are, on the whole, positive. Therefore, it is expected that we will be able to pass into the industrial stage of bitumen recovery with the help of steam. However, it is important to note that the development of such heavy oils will be very progressive and their contribution to world oil supply will only be truly significant in the long term (**Figure 2**).

One of the clear consequences of implementing new technologies is that they are increasing costs. However, cost pressures do not just come from devising new advanced technologies and processes. They also arise due to problems associated with sourcing sufficiently skilled human resources (particularly in remote locations), with the added complications of installing infrastructure in new domains and managing the increasingly stringent environmental requirements associated with project operation.

The complexity of new projects leads

to an increasing length of time to put oil in production. The large, complicated projects that are currently being devised require often much more than five years to put oil or gas in production. In the deep offshore, for example, it typically takes more than eight years between the discovery of a new reservoir and it being put in production. The reasons for this phenomenon include the complications associated with technologically advanced new projects, the overheating that exists in certain elements of the service sector, and, in some cases, the lengthening of project approval procedures by the authorities of host states.

Thus, in short, technological advances are enabling companies to continue expanding production to meet the ever-growing demand for energy. But the associated financial risks are increasing and, given that discovering and producing hydrocarbons is never a sure thing, profitability remains a key challenge in a context of high costs and high uncertainties. In other words, IOCs – known in the past by the name of 'Big Oil' – need to keep strong financially, preserve and foster their skills base, while remaining diversified and integrated. However, nothing can be done without the investments needed to maintain a healthy supply chain.

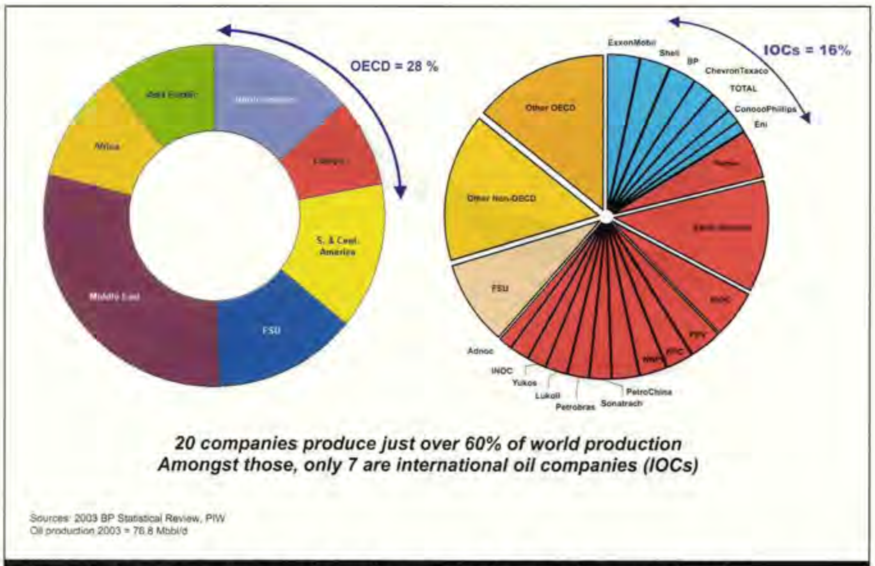

Figure 1: The super majors remain small companies in a very fragmented market

Future issues

When considering how future production requirements can be met, it is also necessary to think about the important issue of sustainable development. Although some sections of the media and society portray the oil and gas industry as dirty and polluting, I believe we are actually at the forefront of many environmental initiatives and are continually striving to limit the impact of our activities on the environment.

Such progress is essential as the continued dominance of oil and gas in the vast majority of its many markets is without question. The application of alternative energies is increasing both in the UK and around the globe. Such technologies will undoubtedly play an important role in the overall energy mix in the long term – especially when it comes to wind and solar power. However, starting from today's low levels, they will only account for a few percent of total energy production in 2015, even with an annual growth of over 10%.

For me, sustainable development means making the most of the resources we have access to and minimising the environmental impact of our activities – such as flare reduction initiatives and emissions trading schemes in the North Sea. Achieving a more sustainable future is not something that can be accomplished easily. It requires the right regulatory and fiscal framework – one that encourages the efficient deployment of expenditure on suitably targeted projects.

Moreover, a country can clearly not achieve a sustainable future in isolation. This is particularly true when one considers the implications of ensuring access to energy for consumers in developing countries. The enormous difference in per capita energy consumption between countries indicates that the developed world will have to improve its level of energy efficiency to allow the developing world sufficient access to energy to enable their economies to grow efficiently. On their own, China and the US accounted for 60% of the world oil consumption in 2004. Perhaps a good start would be to do something about the love of gas-guzzling SUVs in the US!

Is it really sustainable to speak about transporting more and more people, faster, further, more often and cheaper? To do so will need innovation and investment from plane and car manufacturers, adaptability of consumers and other markets.

Therefore, when it comes to preparing the energy sector as a whole for the long term, I believe it is vital that industry and governments around the world work hand-in-hand to ensure an appropriate and achievable environmental framework is put in place for the benefit of all citizens of the world.

UK role

Finally, I would like to finish by saying a few words about oil and gas production in the North Sea. In particular, to observe what a success story the oil and gas industry has been for the UK.

To date, the industry has made cumulative investments of £220bn (2004 money), produced 34bn boe and paid cumulative taxes of £203bn. To put this in context, the UKCS remains the fourth largest gas producer in the world and the 11th in oil.

As noted earlier, the difficult operating environments of the North Sea have led to many technologically ground breaking developments – particularly when the industry was expanding in the 1980s. Even now, in its relatively mature years, breakthroughs are still being made in the province thanks to the skills and inventiveness of the people and companies operating there. One thing I have found while working in the various corners of the world, is that one is never very far from a colleague who has worked in the North Sea. The development of such skilled individuals, for which there is a pressing international demand, is something of which the industry in the UK should be very proud.

Although North Sea production was attaining a peak at the end of the 1980s, the pessimistic projections regarding the speed of decline were never realised. To a significant degree, this is because the new, more favourable, fiscal terms enacted in 1990 facilitated the development of small, satellite fields that could use existing infrastructure. In fact, it is estimated that the fiscal changes introduced, particularly, the removal of PRT (petroleum revenue tax) in post-1990 fields, resulted in higher oil and gas production. It is this pragmatic fiscal approach that will enable the UK to realise the full benefits of the resources contained in the North Sea. This remains a huge prize. There is a potential 28bn boe still to be produced, of which between 5bn and 9bn remain to be found by exploration. Around 260,000 people are directly employed by the

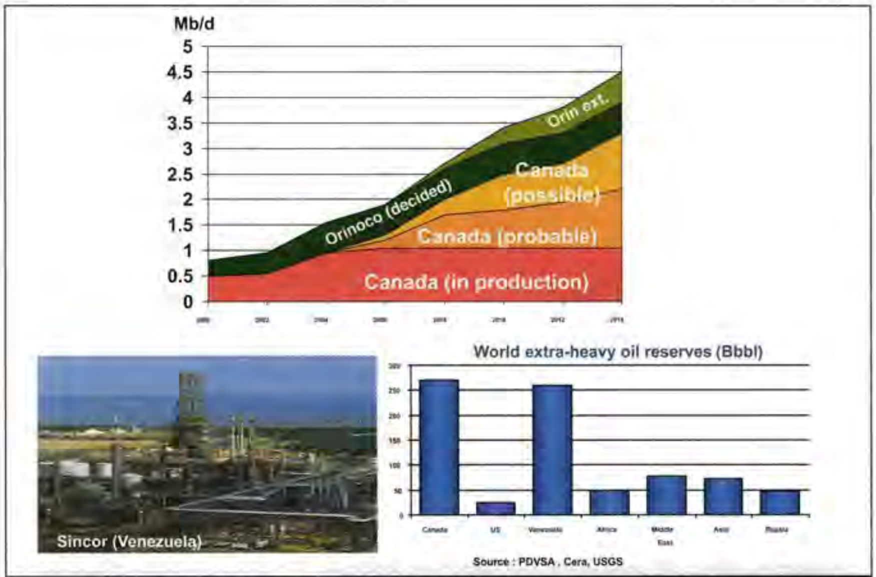

Figure 2: Development of extra-heavy oil in Canada and Venezuela will have an important impact – but it will be very gradual

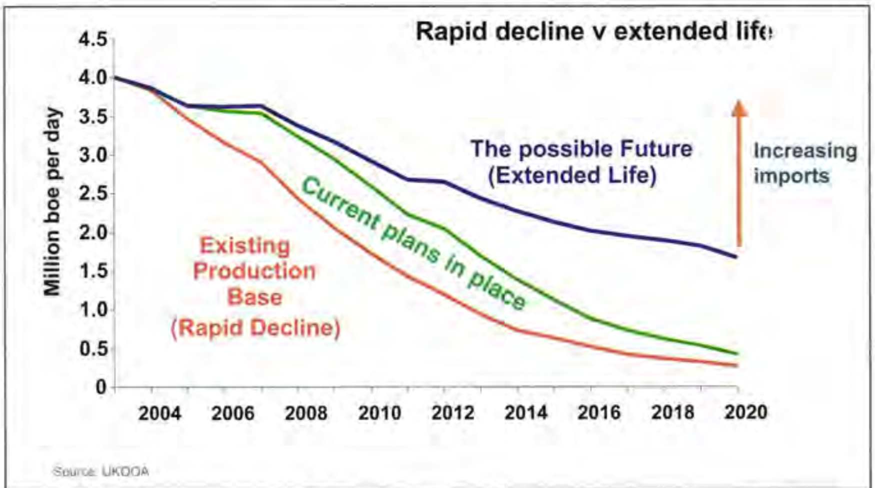

Figure 3: UK North Sea: a tale of two futures

upstream industry. When we read newspapers speaking of a dying industry, are they just ill informed? Or do they have another agenda?

Despite the intensive efforts of the industry to slow the rate of production decline, the UK is progressively passing from a state of complete self-sufficiency to being a more import dependent country. While these trends are well established and cannot be reversed, there are ways to mitigate them.

The tale of two futures shown on this graph (see **Figure 3**) is the difference that adventurous investors, big and small, in cooperation with an experienced supply chain, can make if the government of this country keeps a pragmatic fiscal approach to maintain the long term competitiveness of the North Sea and realise the full benefits of the national resource. Given that oil and gas will represent 75% of the primary energy demand in the UK in 2020, the choice is obvious – maximize the recovery of the basin. What we do not produce will not generate tax and will have to be imported.

One response is to extend the area of operations into new, frontier zones like the harsh, deepwater basin of the West of Shetland's region. Another response is to develop resources that can be found at increasingly greater depths, which in fact means developing 'deep gas' like HP/HT reservoirs of the Central Graben. These are the latest 'adventures'.

The development of the HP/HT Elgin-Franklin field, for example, was a major industrial project. The field, located at 5,500 metres beneath the seabed, is the deepest in the North Sea and is the world's largest HP/HT gas development. With reservoirs at exceptionally high pressures (1,100 bar) and temperatures (190°C), it took over a decade of ground breaking thinking and new approaches at all stages to unlock the value from these complex reserves. Its coming onstream in March 2001 at a total capital expenditure of £1.65bn marked a milestone in the recent history of the North Sea.

This achievement – a striking example of innovative technology at work – is all the more impressive given that Elgin/Franklin exports gas at near-sales quality and now supplies up to 6% of the UK's daily gas needs.

We are still in the early stages of such developments, but I am pleased to say that the success of Elgin/Franklin and the extension of such technology for the development of even deep satellite accumulations such as the Glenelg and West Franklin fields, are showing that we are able to produce gas from these fields – confirming that we are still pushing the limits of the North Sea.

These projects remain very complex and expensive and it is necessary to ensure the right framework is established to ensure that these frontier plays are able to realise their potential.

Closing remarks

In conclusion, it is clear that the oil and gas industry will not be standing still over the coming years and that many challenges will enable the adventure to continue.

I hope I have convinced you that, despite the adventurous nature of oil and gas activity, oil companies and the service companies have the experience of risk management, the track record of developing new technologies and the know-how to build relationships. In this way the great adventure to serve the energy needs and well being of people the world over will continue.

There is a strong caveat, however – we need to attract the new and most talented young men and women to work in the oil and gas sector. They need the vision to make this industry the most advanced in terms of world citizenship. They need to participate in the great transformation as the energy sector moves towards new frontiers, whether it be hydrocarbons or new energies. A sense of adventure, combined with the vision and the boldness to take calculated risks, remain at the heart of our business. I have no doubt that the importance of the challenges will finally attract a new style of oil people who will be the proud holders of the heritage of Lord Cadman.

**Presented for 'outstanding services to the petroleum industry', the Cadman Memorial Award commemorates the late Lord Cadman of Silverdale, a former Chairman of the Anglo-Iranian Oil Company (now BP) and past President of the former Institute of Petroleum (now the Energy Institute).*

A safe platform

Much has been made of the spyware problem in the technology pages of magazines recently, particularly as far as it impacts on financial services companies. However, in the oil and gas sector, IT managers are confronted with different working conditions that can make the threat even more difficult to manage. Chris Message, *ICT System Manager at Dolphin Drilling explains how the company is securing its computers from spyware and other forms of malware at its remote drilling platforms.*

Aberdeen-based Dolphin Drilling, part of the drilling contracting business segment of Fred Olsen Energy, currently manages and operates eight semi-submersible units and one deepwater drillship. Because of the nature of its operations, the company has to manage all the IT issues faced by a normal business – but in remote locations, where it is difficult to get support staff out to the rigs in the event of downtime on the IT network.

The company has long-recognised the need to counteract the growing threat posed by viruses, Trojans, worms and spyware to its computer network. It has a number of specialised staff based out on the rigs, with each vessel having between 10 and 30 PCs configured on a LAN (local area network), which is connected to the company's wide area network (WAN).

Dolphin Drilling foresaw that, with the outbreak of new worms such as Sasser, Blaster and other virulent malicious code, it was at risk of losing parts of its WAN and facing severe downtime in the event of infection. Any downtime that disrupts the company's ability to communicate data to and from its head office in Aberdeen, or sub-offices located around the world, would be expensive to rectify in terms of lost productivity. Also, with the growing threat of spyware, the company was keen to find a way of proactively removing the threat to its systems.

Of course, the company was already protected by the usual antivirus software and firewalls. However, with the proliferation of new forms of worm, it predicted that this was only effective against the last known outbreak of malware. If a new worm or Trojan came on the scene, that could get around Dolphin Drilling's antivirus software, the company would have been vulnerable. Also, with the limited number of staff based on the rigs, the company simply could not afford the manpower to have staff running around installing fresh patches every time a new Windows vulnerability was announced.

The search began by looking for a solution that would supplement the existing perimeter security by protecting the PCs at the point of use. This would ensure that even if one of the machines got infected via a bad file being downloaded from the Internet, or through a new virus causing a firewall breach, the malware would not be able to run on the machines and so the risk of downtime from infection would be eliminated.

The solution

After looking at various types of security software on the market, it was decided to run a pilot of SecureWave's Sanctuary Application Control. This employs a 'white list' approach, whereby only known and authorised software applications are able to run on each PC. Everything else is blocked from running. Sanctuary sits in the kernel of the operating system and actually checks the binary code of all software before allowing it to run. So, even if a file looks like an authorised application, if there is a discrepancy in the binary code it will be prevented from running on the machine.

The result is that Sanctuary creates a secure computing environment, where, even if an employee inadvertently infects the machine though Internet use, or through opening a bad file attachment, the malware will be prevented from running, so no downtime will be caused. In addition, malicious code used for stealing data will be prevented from activating on the machine, so no information will be leaked out while the machine is connected to the web.

Comparative study

The pilot began with the installation of Sanctuary Application Control on 12 machines in January 2003. As part of a phased roll-out to compare and contrast the efficacy of the solution, some computers at Dolphin Drilling continued to be operated without the Sanctuary application having been installed. This paved the way for a revealing comparative study between those machines protected with SecureWave's Sanctuary Application Control and those protected only by antivirus and firewall security.

After a year of running the pilot, it was found that all the machines that were protected with Sanctuary Application Control were completely free of all known malware, but all those that were not protected with Sanctuary had been severely infected with viruses, spyware and malware – despite the fact that the entire network was protected with antivirus software and firewalls. Sanctuary provides a secure environment for staff to carry on working using the applications that they need to do their jobs, without worrying about the latest spyware, Trojans or viruses disrupting their work or compromising data security. Put simply, Sanctuary allows staff to get on with the job, without compromising the company's network security.

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A new and highly participative **3-day** course which covers the principles, techniques and skills involved in the effective management of working capital in the oil industry, blending a clear theoretical framework with extensive use of real-life examples and case studies.

In recent years, there has been growing recognition of the significant potential for improved financial performance from improved management of working capital – both directly from the immediate release of cash and, indirectly, by improving the return on capital employed. A key challenge in achieving these improvements is caused by the fact that the actual levels of working capital are effectively determined by the day-to-day actions of large numbers of staff, in each of the majors, running to tens of thousands.

Who should attend?

- *Senior Business Executives, Strategic and Business Development Planners and Project Managers who wish to refresh their understanding and enhance their skills in managing and improving working capital performance.*
- *Any staff (Technical, Commercial, Financial, etc) whose work impacts directly on working capital performance and who need to acquire improved competencies for their current work and/or for their career development.*

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This **4-day** course will examine the impact on supply and distribution of: refineries' output and fuels' specifications; product sourcing – parent-company refinery, open-market, ex-rack, exchanges; primary-supply mechanisms used; terminal design and location. The overall effect of the network, network planning, and that of competitor locations on routing, load optimisation and backhauling operations will be discussed, as well as the benefits of multi-shift delivery patterns. Staffing levels and training, safety and environmental issues, transport operations, together with benchmarking techniques will also be scrutinised.

Who should attend?

Logistics and distribution personnel, contractors, managers with network planning, supply and transportation responsibilities; marketing managers and planners; supply, logistics and distribution analysts; major oil companies' personnel with strategic or operational roles; finance and performance measurement managers.

NEW COURSE

European and UK gas supply and demand

27 September 2005

EI member: £550 (£646.25 inc VAT) Non-member: £650 (£763.75 inc VAT)

This course focuses on sources of gas supply, likely demand trends, gas supply chain structure, comparative costs of delivered gas per unit of energy and EU legislation and objectives. The major remaining global gas reserves are located primarily in Russia, Middle East and North Africa. The challenge for the future is to transport these reserves, either by pipeline or in liquefied form, to the major gas consuming regions (eg EU-25) in a cost effective and reliable manner.

Who should attend?

Operations along the gas supply chain require a wide range of corporate and professional functions of a technical and commercial nature. This course covers issues and skills relevant to all of these functions, including: gas and LNG suppliers competing in the European market, gas and LNG purchasers (gas and electricity utilities) across Europe, gas infrastructure operators, planners, risk managers, gas traders, market analysts, government policy makers, project financiers, facilities contractors, and those providing legal, contractual, commercial and financial advice to operators along the supply chain.

Oil and gas industry fundamentals

28–30 September, 28–30 November 2005

EI member: £1,400 (£1,645 inc VAT) Non-member: £1,600 (£1,880 inc VAT)

This **3-day** course comprehensively covers the oil and gas supply chains from exploration through field development, valuation and risk, production, transportation, processing and refining, marketing, contracts, trading, retailing, logistics, emerging markets and competition with alternative energies. As such, it provides understanding and insight to the processes, drivers, threats and opportunities associated with the core, industry activities.

Who should attend?

Personnel from a range of technical, non-technical and commercial backgrounds, new industry entrants and those with expertise in one area wishing to gain a broader perspective of all industry sectors. It also provides an industry overview for those employed by financial,commercial, legal, insurance, governmental, service, supply and advisory organisations who require an informed introduction to the economic and commercial background and general trends within the oil and gas industry.

NEW COURSE

Safety in refinery and petrochemical plant operation

4–7 October 2005

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ifp enspm FORMATION INDUSTRIE IFP TRAINING

This **4-day** course outlines the risks inherent in the products and equipment handled in the operation of refinery and petrochemical plant. It is designed to assist participants understand and develop the type of attitude that fosters greater safety in plant operations.

On completion of the course, participants will be familiar with the:

- usual risks in the oil industry
- main prevention approaches
- typical safety management practices

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EI Oil and Gas Training 2005

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Economics of the oil supply chain

10–14 October 2005

£2,150 (£2,526.25 inc VAT)

INVINCIBLE

On this **5-day** course, delegates will examine the various activities of the fictional Invincible Energy Company to explore the economic forces which drive the oil supply chain. They will concentrate on the main areas of risk and opportunity from the crude oil supply terminal, through transportation, refining and trading to the refined product distribution terminal.

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

Who should attend?

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

Gas-to-liquids in the context of the global gas industry

11 October 2005

EI member £550 (£646.25 inc VAT) Non-member £650 (£763.75 inc VAT)*

*Includes complimentary Affiliate membership to the Energy Institute

Topics covered will include:

• Developments, trends and forecasts • Overview of the gas-to-liquids (GTL) processes • Intermediate step of synthesis gas (syngas) production • Fischer-Tropsch (F-T) synthesis • Syncrude fractionation and product options • Economic viability of GTL • Cost, breakeven points and economies of scale • GTL versus LNG: economics, market and strategic considerations • Environmental advantages of GTL products • Emerging markets for GTL • Market leaders in commercial GTL developments • Projects in development and some regional perspectives • Case studies: Malaysia, Qatar, Nigeria

LNG – Liquefied natural gas industry

12–14 October 2005

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*Includes complimentary Affiliate membership to the Energy Institute

This intensive **3-day** course covers technical and commercial perspectives of all segments of the LNG gas supply chain from gas field development, liquefaction processes, shipping, re-gasification, storage, supply into a gas distribution network, embedded opportunities for LNG within existing gas markets, supply and construction contracts, project finance and economic valuation. This differs from other LNG courses in providing an integrated insight to the technologies, the markets, the economics and the finance of the industry.

Who should attend?

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

Trading oil on international markets

17–21 October 2005

£2,800 (£3,290 inc VAT)

INVINCIBLE

During this **5-day** course, delegates will become part of Invincible's fictional trading team, taking decisions about the company's activities to maximise profits through an understanding of the economics of trading and the management of inherent price risks.

Delegates will trade the live, crude oil and refined product markets worldwide, under the guidance of an expert team of lecturers, reacting to events as they happen and using real-time information from Reuters and Telerate screens and daily price information from Platts and *Petroleum Argus*.

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

Planning and economics of refinery operations

18–21 October 2005

EI member £1,900 (£2,232.50 inc VAT) Non-member £2,100 (£2467.50 inc VAT)*

ifp enspm Formation Industrie IFP ■ TRAINING

This intensive, **4-day** course will enable delegates to understand the essential elements of refinery operations and investment economics, to review the various parameters which affect refinery profitability and to develop a working knowledge of the management tools used in the refining industry.

Who should attend?

- *Technical, operating and engineering personnel working in the refining industry*
- *Analysts and planners*
- *Trading and commercial specialists*
- *Independent consultants*
- *Catalyst manufacturers and refining subcontractors*

Forthcoming 2005 training courses

Introduction to lubricants **3–4 November**	Financial management of international petroleum contracts **9–11 November**	NEW COURSE	Oil and gas industry fundamentals **28–30 November**	Price risk management in the oil industry **28 November – 2 December**	Overview of the international upstream oil and gas industry **5 December**	NEW COURSE	Geopolitics and risk in the oil and gas industry **6–9 December**

For more information please contact Nick Wilkinson

t: +44 (0)20 7467 7151 f: +44 (0)20 7255 1472 e: nwilkinson@energyinst.org.uk

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Petrobras prepares to process more heavy oil

Photo: Geraldo Falcão/Petrobras

Petrobras is preparing a range of strategies to cope with the fact that volumes of very heavy crude being produced domestically will greatly increase in the next few years. Patrick Knight *reports.*

Over one-third of the 1.7mn b/d of oil now being produced in Brazil has an API of less than 20° – 60% of it has an API of between 20° and 30°, while only 7% has an API of more than 30°. Some 80% of these crudes come from fields in the Campos basin in Rio de Janeiro state. However, with an estimated 15bn barrels of very heavy oil – some of it with an API of 15° or less – estimated to be in place in Brazil, both the amount and the proportion of heavy crudes in the total will rise steadily from now on, as new fields are developed.

Two large new platforms were put onstream in the Campos field earlier this year and, if all goes according to plan, at least 200,000 b/d of crude will be added to production by the end of 2005. This will take Brazil to the verge of self-sufficiency, raising total output to more than 1.8mn b/d. With several more platforms now being built and new fields developed, output is forecast to increase to more than 2.3mn b/d by 2010.

Exports and imports

During 2004, an average of 180,000 b/d of heavy oil, which Brazil's 11 refineries were unable to process, was exported. The refineries were originally built in the 1960s and 1970s and designed to handle crudes from countries in the Arabian Gulf – oil with an API of more than 30°. Although most have been extensively modified in recent years, there is a limit to the proportion of heavy crudes they can cope with.

As well as the heavy crude, a large volume of fuel oil – demand for which is falling in Brazil – was also exported last year.

Many industries, particularly those in urban areas, have switched to natural gas, of which substantial amounts have been found in recent years. Demand for this fuel has doubled in the past six years and consumption is now growing at about 15%/y. Brazil also has a large surplus of gasoline – about 200,000 b/d is currently exported. This surplus is explained by the fact that alcohol now costs much less to produce than gasoline, and has thus come to account for a quarter of all the fuel used by light passenger vehicles. Natural gas, which is even cheaper still, now fuels about one million mainly high-mileage vehicles as well.

Brazil has a very small railway network and most of the navigable rivers are either in the Amazon region, where very small quantities of goods are moved, or tend to run in the 'wrong' direction and do not reach the sea. As a result, more than 80% of goods moved are carried by truck, many by extremely long distances. Because of the country's overwhelming dependence on road transport, almost 50% of all the road fuel used in Brazil is diesel. Close to 40bn litres of diesel is now consumed each year, and about 10% of it has to be imported.

Petrobras could, of course, continue to export more of the heavy crude it will be producing, while importing increasing volumes of light crude and light products. As well as diesel, such products now include naphtha and LPG (widely used for cooking). The surplus fuel oil and gasoline could also continue to be exported.

However, even before the recent surge in the price of crude, and the fact that the gap between the price of light and heavy crude has widened to the current 20% or more, Petrobras had decided that it made economic sense to set about processing much more heavy crude.

Processing strategy

Petrobras Director of Supplies, Paulo Costa, provided *Petroleum Review* with details of a three-pronged programme to achieve this.

- Retarded coke plants are to be built at six of Brazil's 11 refineries in the next few years. This means that rather than being converted into fuel oil or asphalt, the residues from catalytic cracking will be processed into coke for use in the metal processing industry, as well as medium fractions – notably diesel, gasoline and LPG. From each cubic metre of residues processed in the new plants the yields will be: 44% of diesel, 18% of gasoline, 30% of coke and 5% of LPG.
- A new 150,000 b/d petrochemical plant to produce propane, ethylene and a range of aromatics from oil with an API of between 18° and 12° is to be built in Rio de Janeiro state. Most of the crude will come from the Marlim field in the Campos basin.
- Petrobras has signed a memorandum of understanding (MoU) with PdVSA of Venezuela, which envisages the two companies building a brand new 150,000–200,000 b/d refinery at a location still be determined, but somewhere in the north-east of the country. The refinery will exclusively use very heavy oil as a feedstock. Costa said study groups are now analysing details of this project, notably what proportion of the shares each company might have. This would determine how much Venezuelan and Brazilian crude might be used. The cost of transport and logistics would play a large part here, comments Costa.

Costa went on to explain that the first retarded coke plant started operating at Petrobras' largest refinery, at Paulinia in Sao Paulo state, in October 2004. The new plant is now processing 5,000 cm/d, or about 35,000 b/d, of heavy crude, and among the products produced is 12,500 b/d of diesel. He said that it is planned for the six such plants to all be operating by 2010. Between them they will handle some 150,000–200,000 b/d of heavy crude.

Costa noted that although several refineries in the US are able to handle very heavy crudes, few refineries in Europe are designed to run such crudes. He anticipates that the proportion of heavy crude being produced worldwide will increase, and that of lighter crudes will fall from now on. This trend will ensure that the price gap between the two types will continue to be as wide as


Photo: Geraldo Falcão/Petrobras

it is now, or may even widen further. For this reason, it makes very good sense for Brazil to refine as much of what is produced domestically as possible.

Although the average cost of refining will rise slightly once the new plants are all operating, this will be more than compensated for by the fact that the extra mid-range products which will be made will be worth substantially more than the fuel oil and asphalt they replace.

Costa anticipates that the price of fuel oil will continue to fall steadily in the future, as it is gradually replaced by natural gas around the world.

The new coking plants themselves will not contribute any extra capacity at the refineries. However, Costa says that between now and 2010, between 180,000 and 200,000 b/d of new capacity will be added to Petrobras' 11 refineries, with an extra 60,000 b/d due to come onstream at the refinery in Porto Alegre this year.

If the plans for the new petrochemical plant and the new refinery are taken into consideration, about 400,000 b/d more domestic crude could be processed in Brazil in five years' time than now.

Currently, 80% of all the crude refined in Brazil, about 1.3mn barrels, comes from domestic sources. But the proportion of national crude being handled is expected to form up to 85% of the much larger total to be processed by 2010. Despite the increase in the amount of heavy oil being refined in Brazil, Costa anticipates that some crude, as well as fuel oil, and gasoline, will continue to be surplus to domestic requirements, so will be exported. Exactly how much will depend on how much more light oil is found in the near future.

Bucking the trend

Bucking the trend of the past few years, some oil of close to 30° API was found in a field in Espirito Santo state last year – the first major find of light oil to be made in Brazil for several years. Petrobras is to give priority to developing this new find and it is hoped that up to 150,000 b/d of light oil will start to flow from the new field in about two years' time.

It is hoped that the light and heavy crudes can be blended together to form one feedstock. This should prove possible in most cases. However, Wagner Trindade, the co-ordinator of Petrobras' research into all aspects of producing very heavy oils, suggests that the special characteristics of some of the very heavy oil may make such blending difficult or impossible. Only time and experience will tell, he says.

Petrochemical programmes

As well as being responsible for refining, Costa is in charge of Petrobras' petrochemical programmes, a sector which is to receive considerably more investments in the future than for many years. Petrobras used to dominate Brazil's petrochemical industry, in the same way as it still does E&P, refining, and transport. However, the company was obliged to dispose of most of its petrochemical holdings in a privatisation programme which occurred in the early 1990s.

Costa says that while Petrobras has maintained a major share in the first-generation complexes, which are all adjacent to its refineries, and in some second-generation projects as well, it is not now involved in any third-generation plants, nor in managing these facilities. In the future, the company plans to take larger shareholdings, and to participate in management.

Costa also says that Petrobras, which now makes fertiliser from natural gas at two plants in the north-east, is planning to build another large new fertiliser plant in the centre-west of the country, where gas imported from Bolivia will be used.

There has been a huge increase in the amount of oilseeds and grains produced in this region in the past few years, but 60% of the nitrogen-based fertiliser used in Brazil now has to be imported, notes Costa.

He refused to be drawn as to whether some of the gas which has been found in fields under deep water in the Santos basin, offshore Brazil's wealthiest state, Sao Paulo – which now gets most of its energy from other states – might be used to make fertiliser there. One of Brazil's largest complexes of fertiliser plants, which processes mostly imported ingredients, is located at the port of Santos, adjacent to Petrobras's Cubatao refinery.

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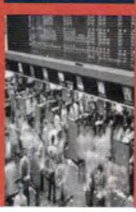

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Did capacity erosion slow in 2004?

This year's BP Statistical Review of World Energy *(June 2005) once again provides the basic data with which to analyse industry trends.* Chris Skrebowski *has used the latest oil production data to try to determine the degree to which capacity erosion slowed in 2004.*

For the last two years *Petroleum Review* (August 2003 and August 2004) has re-presented the BP oil production statistics so as to separate countries whose production is in sustained decline from those whose production is expanding. In 2003 a total of 18 significant producers were in sustained decline, while two others – Iraq and Nigeria – had experienced social/political upheavals that led to extended loss of production during the year. In 2004 the total number of significant producers in decline rose to 20. Syria is now fairly clearly in sustained decline, with the partial recovery seen in 2001–2003 having run out of steam and reversed in 2004. The other new decliner is the 'other Asia-Pacific' category, which groups the region's smaller producers.

Capacity erosion has two underlying drivers – physical depletion of the reservoirs in production and/or lack of investment to maintain/restore production capacity. It is often unclear which is the most important and, in most cases, both causes are involved to a greater or lesser degree. When a country has been in sustained decline for some years it is usually safe to assume that the cause of the capacity erosion is the lack of producible reserves. For countries such as the UK, Argentina and Oman this is clearly the case, with discovery and new development too low to offset the established capacity erosion. In the case of Venezuela, a lack of investment to maintain capacity and delineate new reserves has been the principal cause of recent capacity erosion. Higher investment expenditures in 2004 appear to have led to an expansion of Venezuelan capacity. Small producers are swung around on the discovery or output of single fields, so must be analysed with care.

This year's re-presentation of the BP statistics has been listed on the basis of output change over the last three years (2004/2001) as shown in the first column (see **Table 1**).This is done to damp down the year-to-year swings and anomalies. In the three-year 2004/2001 period, capacity erosion ranged from Australia's loss of just over 26% of capacity to Tunisia's loss of just under 3%. In sharp contrast to the 20 countries (excluding Iraq) that experienced capacity erosion in 2004, there were 33 countries where production increased (or 34 if Iraq's production rebound is included). With virtually every country (with the possible exception of Saudi Arabia) operating at capacity in 2004, production and production capacity are now virtually identical.

Capacity expansion in the three years between 2001 and 2004 saw 24 countries recording production gains of over 10%, 13 of which grew by over 20%, eight by over 30%, five by over 40% and three by over 50%. The three star performers over the period were Chad, where production, although only starting up in 2003, is now well on the way to its reported capacity of 200,000 b/d; Equatorial Guinea, where production reached 350,000 b/d (probably quite close to current installed capacity); and Kazakhstan where production continued the rapid expansion trend seen since 1997, reaching fractionally under 1.3mn b/d in 2004.

In 2004 and 2005 the BP statistics were revised on the basis of various official primary sources. This contrasts with the pre-2003 position, where the basis was predominantly data from the *Oil & Gas Journal*. The effect of this can be quite significant. In this years' tabulation both the original 2003 data as published in the 2004 *BP Statistical Review* and the revised 2003 data as published in the 2005 *Statistical Review* have been listed (the latter as 2003r). The single largest change is for Saudi Arabia, where all the previous years' data have been listed. According to BP this better reflects data about gas liquids from gas plants. In the tabulation overleaf, both the 2004 and the 2005 series have been published. Only the 2005 series have been used for the totals and the 2004 series is in italics. The only other really significant change is for Venezuela, where, if the 2005 data is used, there has been a large recovery in production (+358,000 b/d), whereas if the 2004 data is used, there has been a small capacity erosion (7,000 b/d).

On the basis of the latest (2005) BP

continued on p45...

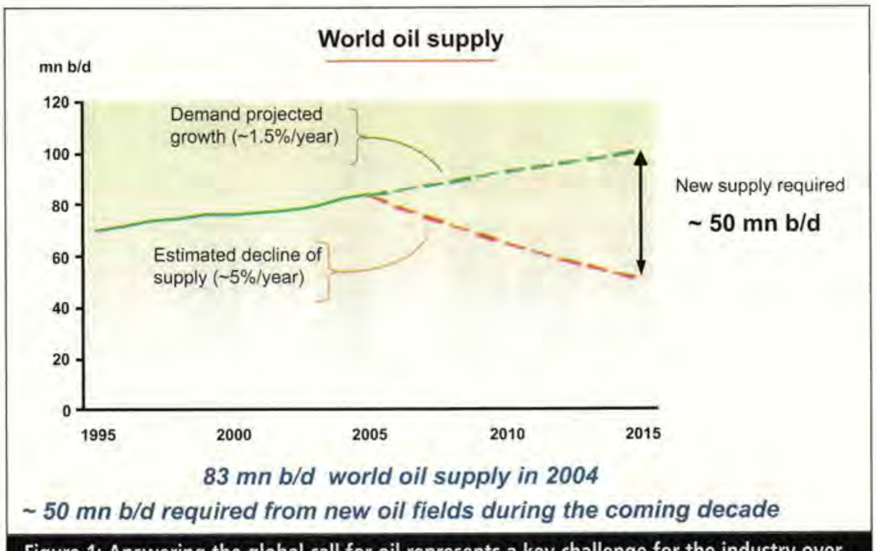

Figure 1: Answering the global call for oil represents a key challenge for the industry over the coming decade *Source: Total, Michel Contie's Cadman lecture, July 2005 (see p32)*

Average % decline/gain 2004/2001	Country and peak production year	1998	1999	2000	2001	2002	2003	2003r	2004	% Change 1-year 2004/2003r	% Change 2-year av 2004/2002	% Change 3-year av 2004/2001
–14.51	Iraq	2,126	2,541	2,583	2,371	2,030	1,344	*1,350*	2,027	50.15%	–7.39%	–4.84
–26.19	Australia – 2000	644	625	**809**	733	731	624	*624*	541	–13.30%	–13.00%	–8.73
–22.50	Cameroon –1997	105	95	88	80	72	68	*68*	62	–8.82%	–6.94%	–7.50
–21.93	Gabon –1996	337	340	327	301	295	240	*240*	235	–2.08%	–10.17%	–7.31
–18.93	Indonesia –1991	1,520	1,408	1,456	1,389	1,288	1,179	*1,183*	1,126	–4.82%	–6.29%	–6.31
–18.31	Oman – 2001	905	911	959	**961**	900	823	*823*	785	–4.62%	–6.39%	–6.10
–18.05	UK – 1999	2,793	**2,893**	2,657	2,476	2,463	2,245	*2,257*	2,029	–10.10%	–8.81%	–6.02
–12.12	Colombia – 1999	775	**838**	711	627	601	564	*564*	551	–2.30%	–4.16%	–4.04
–11.44	Congo(Brazz) – 1999	264	**293**	275	271	259	243	*243*	240	–1.23%	–3.67%	–3.81
–11.11	Uzbekistan – 1999	191	**191**	177	171	171	166	*166*	152	–8.43%	–5.56%	–3.70
–8.92	Yemen – 2001	380	405	450	**471**	462	454	*454*	429	–5.51%	–3.57%	–2.97
–8.81	Argentina – 1998	**890**	847	819	829	808	793	*806*	756	–6.20%	–3.22%	–2.94
–8.46	Romania – 1985	137	133	131	130	127	123	*123*	119	–3.25%	–3.15%	–2.82
–8.06	Syria – 1995	576	579	550	583	572	594	*564*	536	–4.96%	–3.15%	–2.69
–7.83	Venezuela – 1998?	**3,510**	3,248	3,321	3,233	3,218	2,987	*2,622*	2,980	13.65%	–3.70%	–2.61
–6.67	Norway – 2001	3,139	3,139	3,343	**3,416**	3,329	3,260	*3,264*	3,188	–2.33%	–2.12%	–2.22
–6.60	Egypt – 1993	857	827	781	758	753	750	*749*	708	–5.47%	–2.99%	–2.20
–5.58	US – 1971/1985	8,011	7,731	7,733	7,669	7,626	7,454	*7,400*	7,241	–2.15%	–2.52%	–1.86
–5.15	Other Asia-Pacific	218	219	198	194	200	203	*195*	184	–5.64%	–4.00%	–1.72
–5.10	Peru – 1994	119	110	104	98	98	92	*92*	93	1.09%	–2.55%	–1.70
–2.82	Tunisia – 1992	83	84	78	71	73	66	*68*	69	1.47%	–2.74%	–0.94
Total in decline (excl Iraq)		**25,454**	**24,916**	**24,967**	**24,461**	**24,046**	**22,928**	***22,505***	**22,024**	–2.14%	–4.20%	–3.32
Change from year earlier			–538	51	–506	–415	–1,118	*–1,541*	–904			
% change on year			–2.11	0.20	–2.03	–1.70	*–4.65*		–2.14			
0.00	Other Middle East	49	48	48	48	48	48	*48*	48	0.00%	0.00%	0.00
3.94	Brunei	157	182	193	203	210	214	*214*	211	–1.40%	0.24%	1.31
5.00	India	791	788	780	780	794	793	*800*	819	2.38%	1.57%	1.67
5.57	China	3,212	3,213	3,252	3,306	3,346	3,396	*3,401*	3,490	2.62%	2.15%	1.86
6.00	Azerbaijan	230	278	281	300	311	313	*313*	318	1.60%	1.13%	2.00
6.21	Other Europe/Eurasia	507	475	466	467	483	487	*510*	496	–2.75%	1.35%	2.07
7.42	Mexico	3,499	3,343	3,450	3,560	3,585	3,789	*3,789*	3,824	0.92%	3.33%	2.47
	Saudi Arabia 2004*	*9,370*	*8,694*	*9,297*	*8,992*	*8,664*	*9,817*	–	–			
9.29	Iran	3,855	3,603	3,818	3,734	3,420	3,852	*3,999*	4,081	2.05%	9.66%	3.10
9.75	UAE	2,558	2,302	2,499	2,430	2,159	2,520	*2,547*	2,667	4.71%	11.76%	3.25
10.14	Other Latin Am	125	122	129	138	153	163	*156*	152	–2.56%	–0.33%	3.38
12.77	Libya	1,480	1,425	1,475	1,425	1,376	1,488	*1,488*	1,607	8.00%	8.39%	4.26
13.54	Denmark	235	301	364	347	372	368	*371*	394	6.20%	2.96%	4.51
13.75	Canada	2,672	2,604	2,721	2,712	2,838	2,986	*3,004*	3,085	2.70%	4.35%	4.58
14.05	Nigeria	2,163	2,028	2,104	2,199	2,013	2185	*2,263*	2,508	10.83%	12.30%	4.68
14.26	Saudi Arabia 2005	9,544	8,911	9,511	9,263	8,970	10,222	*10,222*	10,584	3.54%	9.00%	4.75
14.81	Trin& Tob	134	141	138	135	155	163	*164*	155	–5.49%	0.00%	4.94
15.33	Brazil	1,003	1,133	1,268	1,337	1,499	1,552	*1,555*	1,542	–0.84%	1.43%	5.11
15.93	Qatar	747	797	855	854	783	917	*917*	990	7.96%	13.22%	5.31
16.03	Malaysia	815	791	791	786	828	875	*878*	912	3.87%	5.07%	5.34
17.16	Kuwait	2,176	2,000	2,105	2,069	1,871	2,238	*2,238*	2,424	8.31%	14.78%	5.72
22.00	Vietnam	245	296	328	350	354	372	*364*	427	17.31%	10.31%	7.33
23.75	Algeria	1,461	1,515	1,578	1,562	1,681	1,857	*1,857*	1,933	4.09%	7.50%	7.92
24.69	Turkmenistan	129	143	144	162	182	210	*202*	202	0.00%	5.49%	8.23
25.29	Thailand	121	132	164	174	191	217	*223*	218	–2.24%	7.07%	8.43
28.61	Ecuador	384	382	409	416	410	427	*427*	535	25.29%	15.24%	9.54
31.59	Russian Fed	6,169	6,178	6,536	7,056	7,698	8,543	*8,544*	9,285	8.67%	10.31%	10.53
31.65	Italy	108	96	88	79	106	107	*107*	104	–2.80%	–0.94%	10.55
33.56	Angola	731	745	746	742	905	885	*885*	991	11.98%	4.75%	11.19
42.65	Sudan	12	63	174	211	233	255	*255*	301	18.04%	14.59%	14.22
43.75	Other Africa	63	56	61	64	65	74	*75*	92	22.67%	20.77%	14.58
54.90	Kazakhstan	537	631	744	836	1,018	1,,106	*1,111*	1,295	16.56%	13.61%	18.30
93.37	Equat Guinea	83	100	113	181	237	249	*249*	350	40.56%	23.84%	31.12
	Chad						24	*24*	168	600.00%		
16.41		47,947	47,146	49,702	50,026	50,018	53,834	*54,550*	58,235	6.76%	8.21%	5.47
	Regional Totals											
1.50	Tot N. America	14,182	13,678	13,904	13,941	14,049	14,229	*14,193*	14,150	–0.30%	0.36%	0.50
–0.72	Tot L. America	6,940	6,822	6,899	6,813	**6,942**	6,741	*6,385*	6,764	5.94%	–1.28%	–0.24
13.87	Tot Eur./Eurasia	14,175	14,458	14,932	15,441	16,259	16,927	*16,968*	17,583	3.62%	4.07%	4.62
9.15	Tot ME	22,742	21,880	23,163	22,512	20,909	22,607	*23,163*	24,571	6.08%	8.76%	3.05
17.77	Total Africa	7,638	7,571	7,800	7,866	7,962	8,401	*8,464*	9,264	9.45%	8.18%	5.92
0.18	Tot Asia–Pacific	7,724	7,654	**7,971**	7,914	7,943	7,872	*7,881*	7,928	0.60%	–0.09%	0.06
–2.80	OECD	21,477	21,082	21,504	21,330	21,402	21,185	*21,161*	20,732	–2.03%	–1.57%	–0.93
8.82	OPEC	30,965	29,561	31,090	30,258	28,503	30,383	*30,686*	32,927	7.30%	7.76%	2.94
0.97	non–Opec excl FSU	35,044	34,951	35,565	35,570	**36,049**	35,917	*35,870*	35,916	0.13%	–0.18%	0.32
31.85	FSU	7,391	7,551	8,013	8,659	9,513	10,477	*10,499*	11,417	8.74%	10.01%	10.62
7.75	**Total World**	**73,400**	**72,063**	**74,669**	**74,487**	**74,065**	**76,777**	***77,054***	**80,260**	4.16%	4.18%	2.58
Change on year			–1,337	2,606	–182	–422	2,712	–	3,206			

Source: BP Statistical Review June 2005: *Re-presentation and calculations by* Petroleum Review
NB: All percentage changes calculated on b/d numbers, unlike BP, who uses the metric tonne numbers for percentage change calculations
*Bold figures are peak production years and totals. *For comparison with 2005, not included in totals.*

Table 1: World oil and liquids production 1998–2004

...continued from p43

statistics, global capacity erosion slowed from 1.1mn b/d per year in 2003 to 0.9mn b/d per year in 2004 – a clear improvement. However, if we use the revised 2003 data then capacity erosion in 2003 would have been 1.54mn b/d. Venezuelan production appears to be the key variable. Over the last year or so there have been wide discrepancies between the official and non-official estimates of Venezuelan production.

The three columns on the right hand side of the table give the average annual loss/gain for the last one-, two- and three-year periods. This gives some indication of whether capacity erosion is speeding up or slowing down and, similarly, for production growth. Algeria and Ecuador provide the best examples of accelerating production growth. The table shows that capacity erosion has slowed for Gabon, Indonesia, Oman, Colombia and Congo (Brazzaville), while Peruvian and Tunisian production actually grew in the last year. In contrast, capacity erosion appears to have accelerated in a number of countries – notably the UK, Argentina, Syria, Egypt and Australia – all large producers. The picture does, however, become more complicated if the initial rather than the revised 2003 figures are used. For example, on the latest (revised 2003) figures the capacity erosion in 2004 was 2.14% but, if the earlier 2003 figure is used, it is 3.94%.

The use of other databases to cross-check the result brings the complication of what is being counted. Production data from the *Oil & Gas Journal* counts well fluids – oil and condensates – rather than all liquids as cited by BP and the International Energy Agency (IEA). The *Oil & Gas Journal* figures itemise many more countries than BP, so may give a better picture of the volumes lost to capacity erosion. Using this database we get capacity erosion of 0.85mn b/d in 2002, 1.15mn b/d in 2003 and 0.84mn b/d in 2004. IEA data is only readily available from a limited number of countries, which coarsens the result. IEA data suggests capacity erosion of 0.84mn b/d in 2002, 1.1mn b/d in 2003 and 0.82mn b/d in 2004.

The conclusion is that capacity erosion did slow in 2004 – probably by around 0.2–0.3mn b/d. Although this is a considerable achievement it is an obvious consequence of high prices leading to capacity-erosion mitigating investments. These tend to be relatively small and rapidly sanctioned investments – extra wells, pumps etc. The fact that so many large producers remain in inexorable decline probably reflects how efficiently these resources have been produced with pressure maintenance and enhanced recovery techniques applied from the start of production.

...continued from p16

Germany is closely entwined with the progress of gas liberalisation as set out in the Second Gas Directive. The directive gives the right of access to storage but allows member states the choice between negotiated and regulated third-party access.

The Madrid forum – set up to assist in the creation of a true internal gas market –recently published *Guidelines for Good TPA Practice for Storage System Operators (GGPSSO)*. The *GGPSSO*, whilst not legally binding, aims to ensure that storage system operators (SSOs) provide the services needed by storage users on a fair and non-discriminatory basis. The guidelines are due to be implemented by April 2006.

In Germany discussions on these issues are caught up in the larger debate on the new energy law. Some companies have already granted access to their storage sites and the new law is unlikely to have any impact on them. However, other German storage operators – mostly regional and local German gas companies – will have to grant access to their storage sites and publish some basic information on access conditions, the technical framework and available capacity. Most new entrants claim that access to storage is only part of the story and without unfettered pipeline access this is unlikely to be of much value.

It remains to be seen whether a surplus of storage will emerge in the German market as it liberalises. Notwithstanding this possibility, a number of new storage developments are planned. For example, the Epe facilities in northern Germany have capacity for expansion and a number of other projects are also being evaluated.

Looking ahead

European storage is entering a new era as liberalisation moves slowly forward. Experience from the UK suggests that some storage operators may experience loss of value during the transition period.

However, a fully liberalised market is likely to provide sufficient incentives eventually for new investments in storage (at least for peak day and trading requirements) and storage will continue to play an important role in balancing supply and demand.

Gas Strategies provides consultancy services covering commercial, strategic and financing issues of the worldwide gas and LNG business. Advice stretches from emerging market studies to restructuring and liberalisation of mature markets. The company carries out project finance, due diligence and market analyses and provides advice on supply, demand, pricing and security of supply issues. For more details, e:* **consult@gas-strategies.com

Climate change and the way ahead

Sir David King speaking at the EI Summer Lunch
Photo: Jim Four

Speaking at the EI Summer Lunch held at the Royal Automobile Club, London, on 12 July 2005,* Sir David King, *the UK Government's Chief Scientific Advisor and Head of the Office of Science and Technology, tackled the thorny issue of climate change. The following are some key highlights of his presentation.*

Sir David began by reminding his audience of the main objectives of the UK government's Energy White Paper – *Our energy future: Creating a low-carbon economy*. Published in 2003, the paper defines a long-term strategic vision for the UK's energy policy. Keeping the principals of sustainable development in mind, it looks ahead to 2050 to set the overall context, and sets out the challenges and policies that need to be pursued over the next 20 years and beyond to meet four key goals:

- To put the UK on a path to cut its carbon dioxide (CO_2) emissions – the main contributor to global warming – by some 60% by about 2050, with real progress by 2020.
- To maintain the reliability of energy supplies.
- To promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve productivity.
- To ensure that every home in the UK is adequately and affordably heated.

Sir David went on to note that the political situation 'could be deemed to have changed' since publication of the Energy White Paper – citing 'Putin's Russia' in particular at this juncture as well as the fact that we now have 'British trading in carbon dioxide and European Union trading', with an anticipated move to 'global emissions trading after the November meeting in Montreal'. As a result, 'we have several new drivers coming onboard,' he said, 'and I am sure that the UK government is going to have to return to an evaluation of energy policy once again.'

The science of climate change

Sir David then went on to explain the science of climate change, a 'mature' subject first studied by French mathematician Fourier in the late 1820s, who pointed out that the earth's temperature was determined by the energy balance between incoming sunlight and the outgoing radiation – as illustrated in **Figure 1**. Sir David commented that while the greenhouse effect had 'had bad press recently', we in fact needed it, as 'without it, the earth's temperature would be –18°C'. He went on to explain the later work of UK scientist Tyndall, who discovered that CO_2 and water vapour were the key greenhouse gases controlling radiation absorption levels and whose work was followed by the calculation of Arrhenius showing that a doubling of CO_2 levels would lead to a 5°C rise in the earth's temperature. Today's most sophisticated computers have calculated a figure of between 3°C and 7°C!

Sir David then outlined the earth's carbon cycles and natural carbon sequestration processes, and provided a snapshot of CO_2 levels in the atmosphere over the last 60,000 years (around 200 ppm), 8,000 years ago (around 260 ppm) and in 2004 (379 ppm). He stated that there was 'no doubt in anyone's mind' that the significant rise in CO_2 levels had been 'a direct consequence of the use of fossil fuels'. He commented: 'Today's CO_2 levels are the highest that they have been in the past one million years; indeed, probably the highest they have been since 50mn years ago – the hottest period in the earth's history when there was no ice at the Antarctic.' He continued: 'there are questions about what is the level of CO_2 at which we might lose all the ice at the Antarctic, in particular, the question is what is the level of CO_2 at which the ice on Greenland will melt, leading to a rise in sea level of about 7 metres?'

Decoupling GDP from carbon emissions

Sir David then went on to show (**Figure 2**) that it was possible to 'decouple' GDP (gross domestic product) growth from carbon emissions. 'It will be a challenge of course,' he noted, 'and will require a total revaluation of the energy industry… I foresee a period of transformation in the energy industry unlike any we've had since the whole fossil fuel boom began in the industrial revolution.'

Technological opportunities

Sir David then went on to explain that there was a global concern about energy security and supply, with higher energy prices requiring industry and commerce to examine the costs and efficiency of energy use. He stated that there was a need to 'look at the whole basket of technological opportunities', which must 'include energy efficiency gains'. He stated that he believed it was possible to achieve an energy saving of 60%, but it would require 'proper regulation' and 'public acceptance of the cultural change' that would be necessary.

Sir David then went on to talk briefly about carbon abatement technologies, carbon capture and storage, stating that there needed to be 'much more R&D in these areas', but, 'at the same time, this should not be a fig leaf for business as usual. The technology is not proven and I don't believe it will be there in the next 20 years or so – and we need action much more quickly than that.'

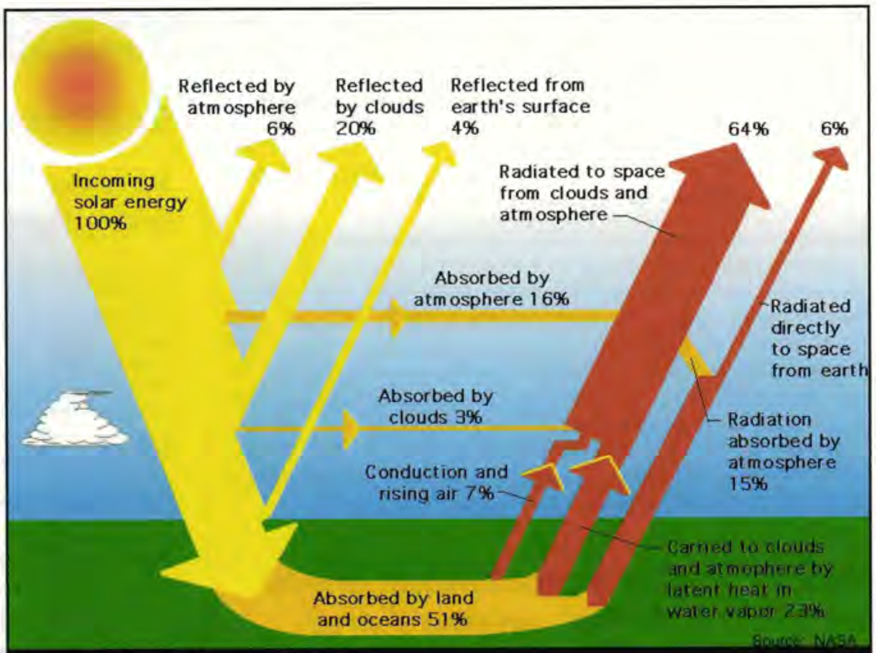

Figure 1: The earth's energy budget

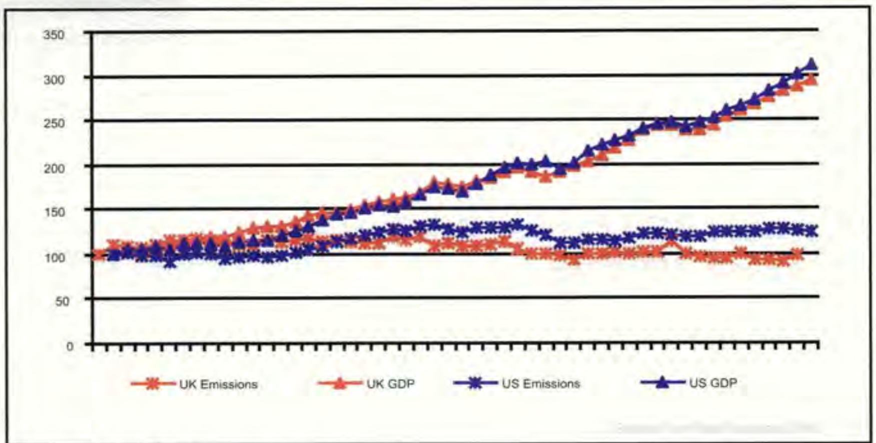

Figure 2: GDP and emissions

A new gold standard

He continued: 'The new factor is emissions trading. When trading started earlier this year the cost was around 8 or 9 per tonne – there was a question as to whether this was high enough to encourage investment. However, I am pleased to see that the market has been a wise arbiter here, and the figure is currently at 29/t … At 30/t quite a range of alternatives becomes competitive on an economic basis – especially if you couple that with the fact that oil and gas prices are rising as they are finite resources… Renewables and nuclear (fission/fusion) will all be important in reducing emissions, but also to maintaining security of supply and to retaining our market competitiveness.'

'I also believe that London is poised to be the financial centre for this enormous new market commodity. Emissions trading will be with us for the next 100 years and I think it is quite possible that the new gold standard, as we move through this century will be CO_2; every country uses energy and there is no single standard that I believe is likely to stand up as firmly as CO_2.'

Sir David ended the afternoon by answering questions from those assembled. Among them was a question on peak oil production – did Sir David expect such a peak and, if so, when? In response, Sir David said that, in one sense, the answer was relatively simple – 'Oil is a finite resource and it is just a question of when it will run out'. He noted that ExxonMobil had forecast 'a plateau in productive capacity' within the next few years and went on to state that, in his view, productive capacity would fail to meet demand within the next 10 years, at which point, alternatives would be required.

After what was a lively Q&A session, EI President, Sir John Collins, presented Sir David with an Honorary Fellowship of the Energy Institute.

**The EI Summer Lunch was sponsored by E.On UK, with Dr Paul Golby, Chief Executive, opening the event by stating that climate change 'is the key environmental challenge facing the energy sector today'. He noted that while much had already been done on both the supply and demand side to develop a low-carbon economy and improve energy efficiency, the UK government needed 'to support industry's efforts to deliver carbon reductions in the longer term'. He stressed as a 'first priority' the need for the government 'to remove current policy uncertainties' in order to create an environment that would 'encourage innovation and investment in low carbon technologies' and help 'maintain UK competitiveness'. He also emphasised the need for closer working between government, industry and universities, and called for increased public awareness of the issue of energy efficiency.*

Fuel effects on the characteristics of particle emissions from advanced engines and vehicles*

(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

To update understanding on emissions from road transport, Concawe is continuing to assess fuel effects on emissions from new engine/vehicle technologies as they approach the market. In this work, two advanced light-duty diesel vehicles, two direct injection gasoline vehicles and three heavy-duty diesel engines covering Euro-3 to Euro-5 technologies were tested on a range of fuels. This report (No 1/05) concentrates on the fuel and engine technology effects observed on a range of individual characteristics of the particulate emissions, measured as part of Concawe's contribution to the larger DG TREN 'Particulates' Consortium. In addition to regulated mass, the total number, surface area and size distribution of the particulate emissions have also been measured.

Fuel effects on emissions from advanced diesel engines and vehicles*

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This report (No 2/05) is the companion document to that outlined above. It describes the results for the regulated emissions, hydrocarbons (HC), carbon monoxide (CO), nitrous oxides (NO_x) and particulates (PM), as well as carbon dioxide (CO_2) and fuel consumption.

Annual LPG Market Review and Forecast 2004/05

(Drewry Shipping Consultants, Drewry House, Meridian Gate, 213 Marsh Wall, London E14 9FJ, UK. t: +44 (0)20 7538 0191; f: +44 (0)20 7987 9396; www.drewry.co.uk*). Price: Hard copy and pdf versions - £995; pdf only - £795.*

The latest findings in Drewry's annual LPG market review make extremely positive reading for ship owners as they are finally experiencing a period of stability and growth. Having experienced dramatic booms and busts since the turn of the century, the report highlights how the various market segments are now performing. It evaluates all the key components in the LPG mix, including such areas as LPG trade patterns around the world, carrier fleet development by sector, analysis of gas carrier new orders and demolition sales, evaluation of LPG vessel values, and trends in consumption and production of LPG, ammonia and petrochemical gases. Among its findings, the report specifically identifies that small LPG carriers enjoyed a very good start to 2004, with spot rates for LPG cargoes in Europe rising to their highest levels since 1995. The report forecasts that prospects for this sector now look better than they have done for many years. However, it does warn that there could be another fall in total fleet capacity if scrapping levels remain high.

Port of London Handbook*

(Port of London Authority, Bakers' Hall, 7 Harp Lane, London EC3R 6LB, UK. t: +44 (0)20 7743 7900; f: +44 (0)20 7743 7998; www.portoflondon.co.uk*). 128 pages. Price: Free.*

A new handbook with key information on the 70-plus independently owned and operated port terminals and facilities of the Port of London, including maps showing the location of the terminals and listings of shipping services to and from London, has been published. The Port handles over 50mn t /y of cargo each year.

**Held in EI Library*