JULY 2005

Petroleum review

ENVIRONMENT AND POLLUTION
- Oil spill response – anytime, anyplace, anywhere

REFINING
- Sustaining margins into the future

GAS DEVELOPMENTS
- LNG vessels – the next generation
- Skills shortage to create crewing crisis?

Covering the international oil and gas industry from field to forecourt – exploration, production, refining and marketing

energy INSTITUTE

www.energyinst.org.uk


E&P Technical Specialists Wanted
Visit www.shell.com/careers/ep
Always looking
At Shell, we never stop looking to the future, or for the people that will make it happen. Take now for instance. We're looking for the world's top Exploration & Production talent to join us in building a business capable of real and sustainable growth. If that's you, and you're interested in exploring your potential in an environment characterised by opportunity, flexibility and reward, why not look to your own future at: www.shell.com/careers/ep
Shell is an Equal Opportunity Employer

Petroleum review

JULY 2005 VOLUME 59 NUMBER 702
SINGLE ISSUE £15.00 SUBSCRIPTIONS (INLAND) £215.00
AIRMAIL £358.00

PUBLISHER

energy INSTITUTE

61 New Cavendish Street, London W1G 7AR, UK

Chief Executive: Louise Kingham, MEI

General Enquiries:
t: +44 (0)20 7467 7100
f: +44 (0)20 7255 1472

Editor: Chris Skrebowski FEI

Associate Editor: Kim Jackson MEI

Design and Print Manager: Emma Parsons MEI

Editorial enquiries only:
t: +44 (0)20 7467 7118
f: +44 (0)20 7637 0086

e: petrev@energyinst.org.uk

www.energyinst.org.uk

ADVERTISING

Advertising Manager: Brian Nugent
McMillan-Scott plc
10 Savoy Street, London WC2E 7HR

t: +44 (0)20 7878 2324 f: +44 (0)20 7379 7155
e: petroleumreview@mcmslondon.co.uk
www.mcmillan-scott.co.uk

SUBSCRIPTIONS

Journal subscriptions: Chris Baker, t: +44 (0)20 7467 7114, f: +44 (0)20 7252 1472 e: cbaker@energyinst.org.uk

Membership: Sheila Wallace, t: +44 (0)20 7467 7120
e: swallace@energyinst.org.uk

Printed by Thanet Press Ltd, Margate

ABC MEMBER OF THE AUDIT BUREAU OF CIRCULATION

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: OSRL Hercules spraying dispersant. See p18.

CONTENTS

2004 energy demand– too much of a good thing?

In terms of energy demand, 2004 was quite exceptional – as is vividly illustrated in the latest *BP Statistical Review* (June 2005). This shows that total energy demand grew by 4.32% in 2004, with the largest oil volume increase ever recorded (3.2mn b/d) and the highest percentage increase since 1984. The increase was broadly based, with all fuels and all regions exceeding their respective 10-year averages.

The driver was economic growth, which grew by 4.1% for the world, with every region exceeding its 10-year average – except Europe, which was spot on its 10-year average.

The first point to note is that energy and economic growth have not really decoupled, although for certain fuels and certain regions economic growth can be a multiple of the energy input growth.

Peter Davies, in presenting this year's BP statistics, showed that carbon emissions growth was also a record, growing by 4.5% – the largest absolute increase ever and the highest percentage change since 1976.

The bottom line is stark. Economic growth is still directly linked to energy growth and energy growth is still directly linked to greenhouse gas (GHG) emissions.

Meanwhile, the science linking GHG levels to global warming has never been stronger. Recent work by the Scripps Institution of Oceanography, University of California, San Diego, has linked changes in ocean temperatures with human activity. The importance of this work is that 84% of the earth's extra heat ends up in the oceans. The work also showed that potential natural causes of warming – such as changes in solar radiation and volcanic emissions – had an impact that was many times smaller than human activity.

The scientists claim that they can now match climate models with measured effects, with over a 95% level of confidence. The pattern of warming also now matches an anthropogenic origin. Warming is greatest in the southern oceans, where man-made aerosols are at a minimum. In contrast, in the northern Indian Ocean, a cooler layer of water overlies a warmer one, which is claimed to be the result of the 'shielding' effect of the pollutant haze over southern Asia (which has offset atmospheric warming in the region).

All the signs are that this work is as important as the 'US Surgeon General's' report of 1964 that linked smoking to lung cancer and other diseases.

Now, the parallels with smoking are interesting. To this day, large numbers of people smoke, the science isn't perfect, the data is heavily circumstantial rather than proof positive, but few now contest the link. Indeed, large fortunes have been won in compensation for the damage caused by smoking.

If the parallel with global warming holds, the only way to continue in denial is either to resort to a 'creationist' type faith that global climate science is as undesirable as the science of evolution, or to say that you don't care. Accepting the science and the anthropogenic cause of climate change does not mean that mitigation measures are possible. Although it is fair to ask if much US resistance stems from fear of legal action and lawyers' propensity to sue. The science, the lack of precision and the lawyers have now produced a widespread schizophrenia in both business and governmental circles. Economic growth is the only way we know to improve the welfare of the world's citizens, but we now know that the cost of this growth in terms of climate change/global warming is rising. So what changes should we make? What insurance should be take?

The scientists and environmentalists say move fast and move now. The politicians know that lack of economic growth can cost jobs and, so, votes. The business community is largely caught in the middle – desparately hoping the politicians will keep the playing field level, but also increasingly aware that changes will have to be made.

This has already produced some strange paradoxes. Some 150 US cities have already pledged to meet Kyoto-style targets. Business leaders in Europe and the US are starting to speak out, calling for rules and regulations to give them targets to work to and a level playing field to operate in. Maybe the G8 conference will produce the clarity business requires? The fear is that narrow political calculations will triumph and more time will be lost.

The ways out of the box are few. Solar and wind produce no GHG but

continued on p47...

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

E-DATA

SHEC-Labs has released a web-based energy conversion calculator that is being made available as a free service at **www.shec-labs.com/calc/fuel_energy_equivalence.php** The site will enable users to find out how a litre of liquid hydrogen equates to a cubic foot of hydrogen, a cubic metre of hydrogen or a litre of gasoline. Answering a number of commonly asked questions, it explains how hydrogen compares to other fuels and details the energy content of various fuels.

Lloyd's Register has published a set of comprehensive guidelines to help owners, operators and builders of membrane-type LNG tankers to assess the ability of a containment system to withstand sloshing loads. The guidelines are entitled *Comparative sloshing analysis of LNG ship containment systems* and provide a means of fulfilling the requirement to take sloshing into account during containment system design in Lloyd's Register's *Rules and Regulations for the Construction and Classification of Ships for the Carriage of Liquefied Gases in Bulk*. The guidance document is part of Lloyd's Register's ShipRight procedures and is available for download at **www.cdlive.lr.org** – Lloyd's Register's class information website.

Materials Recycling Week (MRW) has launched a website at **www.mrw.co.uk** that provides businesses with access to a host of news, information legislation, data and in-depth reports. The site also features a 'Legislation Forum'. Run in association with the Department for Environment, Food and Rural Affairs (DEFRA), the Legislation Forum enables users to find out exactly how legislative developments will impact them, by putting questions directly to the relevant government officials. The first subject under discussion is the Landfill Allowance Trading Scheme (LATS), which was launched in England in April 2005.

The Scottish Enterprise Energy Team has completed the formulation of an economic development strategy – a 'route map' – setting out ambitions for the Scottish energy industry by 2010 and outlining how these may be achieved. A summary be downloaded from **www.scottish-enterprise.com/energy** Five strategic themes have been identified as the framework for assessing where and how to direct investment and resources by Scottish Enterprise and partner organisations, to meet the stated aims. These are global business development, commercialisation opportunities from technology development, maximising diversification opportunities, strengthening key industry sectors, and stimulating research collaboration.

UK

Applications for the UK's latest off- *shore oil and gas licensing round hit a 30-year high, with firms applying for a record 279 blocks, the largest number applied for since 1972. A total of 134 applications were received in all by the DTI. Of the 114 companies who applied, 28 are new applicants to the North Sea. The full list of applicants can be found at* **www.dti.gov.uk**

The North Sea Horne and Wren fields *– Tullow Oil's first operated development in the UK – have come onstream at an initial flow rate of 60mn cf/d, soon to be ramped up to plateau production of 90mn cf/d.*

Rig utilisation in the North Sea rose *above 90% in May to a new high, according to Platts' latest* North Sea Letter. *All jack-ups in the region are under contract and all have contract backlogs of six months or more.*

Paladin Resources (58.97%, operator) *and Energy North Sea (41.03%), a subsidiary of Marubeni Corporation, have received DTI approval for the development of the Wood oil field via a single horizontal development well tied back to the existing Montrose production platform. Production will start in late 2006, peaking at over 5,000 b/d of oil and 21mn cf/d of export gas.*

EUROPE

The Norwegian government has *offered 64 blocks in the Barents Sea (30 blocks) and the Norwegian Sea (34). The closing date for applications is 15 November 2005, with awards planned*

Tax hike for Bolivian oil and gas ops

The recently signed new hydrocarbons law in Bolivia has resulted in a substantial tax hike for upstream companies. The imposition of a new 32% effective royalty will increase the government take from the industry by $240mn/y, according to energy consultant Wood Mackenzie.

'Despite impressive exploration success in the last 10 years, Bolivia has struggled to access markets for its gas. Much of the country's gas reserves remain stranded,' explains Gareth Ellis, an analyst on Wood Mackenzie's Latin American Upstream team. In Wood Mackenzie's recently published *Global Oil and Gas Risks and Rewards (GOGRR)* report, Bolivia ranks sixth in the world in terms of discovered gas reserves over the last 10 years. 'The results of the *GOGRR* report are compelling,' comments Ellis, 'but, if you consider only discovered gas for which there is a guaranteed market, Bolivia looks much less impressive.' He continues: 'This is symptomatic of the country's stranded gas problem. High transportation costs have resulted in relatively high city gate gas prices, meaning that Bolivian gas has found it difficult to penetrate established Southern Cone markets, such as Brazil and Argentina, even under the previous – more favourable – tax terms. The challenge now faced by Bolivian operators is how to monetise their already stranded gas in face of the new tax environment.'

The tax increases will have a major impact on foreign companies operating in the Bolivian gas industry. 'We calculate that top producers Repsol-YPF and Petrobras will see a reduction in net cash flow of $95mn and $53mn per year based on current production,' explains Ellis. 'The longer term impact will be more severe as foreign companies will now find it more difficult to monetise their stranded gas reserves.'

Although the economic rent extracted by the government will increase in the short term, the tax increases are likely to deter participants from making the large capital investments required in infrastructure to develop Bolivia's gas industry, resulting in lower government revenues in the longer term.

FPSO Kizomba B *put in place*

Semco Salvage & Marine recently completed tow to location, positioning and associated deck operations for the FPSO (floating production, storage and offloading vessel) *Kizomba B* offshore Luanda, Angola. The project followed the earlier tow and positioning of FPSO *Kizomba A*, completed in 2004.

Kizomba B was towed from Ulsan, Korea, by three large ocean-going tugs – the 165 tonnes bollard pull (bp) sister vessels *Salvanguard* and *Salviscount*, and the 110 tonnes bp *Salvigour*. A fourth tug, the 110 tonnes bp *Salvaliant*, accompanied the convoy as escort. The FPSO arrived offshore Luanda on 28 April. The positioning spread was then joined by the 146 tonnes bp AHTS *Salvana*, in the role of fifth positioning tug.

during 1Q2006. A full listing of the blocks put out to tender can be found at **www.dep.no/oed/english**

Plans for Statoil's Statfjord late life and *Tampen Link pipeline projects in the North Sea have been given the green light by the Norwegian Storting (parliament). Investing NKr16.1bn will allow additional volumes to be recovered by converting the field's installations from handling oil with associated gas to gas with associated oil. Recovery factors of close to 70% for oil and 75% for gas are expected to be achieved via the Statfjord late life project. Additional recoverable volumes are put at 32bn cm of gas, 25mn barrels of oil and 60mn barrels of condensate.*

Lundin Petroleum has sold its 12.5% *participating interest in the Seven Heads gas project and certain other offshore Irish oil and gas assets to Island Oil & Gas.*

Aker Verdal has been awarded a con-*tract from Nexen Petroleum UK for fabrication of the flare and bridges for its operated Buzzard field in North Sea blocks 19/5, 19/10, 20/1 and 20/6. Delivery is slated for March 2006.*

Recovery from Statoil's Norne develop-*ment in the Norwegian Sea is to be improved by more than 10mn barrels of oil under a contract award. Production is due to begin in the autumn of 2006.*

The Danish Energy Authority has pub-*lished the terms of new oil and gas licences in the Danish part of the North Sea. Oil companies are invited to send in tenders by 1 November 2005.*

Shell reports that it has made a 'signif-*icant' gas discovery in sandstones of Jurassic age in the Onyx South West prospect in block 6406/9 of production licence (PL) 255 in the Norwegian sector of the North Sea.*

NORTH AMERICA

China's Sinopec is understood to have *acquired a 40% stake in the Northern Lights oil sands project in Alberta from a Canadian company for C$105mn ($83mn). The project has a design capacity of more than 100,000 b/d of synthetic crude oil. Synenco, with 60%, will be the operator of the project.*

Eni has reported first oil from the K2 *field in deepwater Gulf of Mexico Green Canyon block 562. The first well placed on production had an initial flow rate of 8,000 boe/d. Reserves are estimated to be in excess of 100mn boe.*

New high-spec rig for Mittleplate

International rig design and manufacturer Bentec Drilling & Oilfield Systems – a wholly-owned subsidiary of Abbot Group – has unveiled its new 2,500 HP rig T-150 that has been built for the Mittelplate field, lying under the Waddensee mudflats off the west coast of Germany. Mittelplate is Germany's largest producing offshore field – holding more than 60% of the country's existing oil reserves and producing 60% of total domestic production. It has been developed by RWE Dea (operator) and Wintershall.

As the rig will be operating in an environmentally sensitive area it has been manufactured to an extremely high specification, with a zero spill policy, low noise and reduced emissions. The new drilling unit is capable of drilling to a depth of 25,000 ft. It will allow the Mittelplate consortium to raise production and reduce the overall field production time, which will also reduce the long-term impact on the area.

PetroChina and Shell to develop Changbei

PetroChina and Shell have announced that they are jointly proceeding with the development of the Changbei natural gas field in Shaanxi Province and Inner Mongolia Autonomous Region, China. Shell, which will be the operator of the project under a production sharing contract with PetroChina, has signed drilling contracts and letters of intent (LOI) for the award of engineering, procurement and construction (EPC) contracts for the field development.

The field is expected to start delivering 1.5bn cm/y of gas to markets in Beijing, Shandong, Hebei and Tianjin by 2007, rising to 3bn cm/y by 2008.

Total development costs for the full lifecycle of the project will be about $600mn, covering the construction of the central processing facilities, inter-field pipelines and development drilling of about 50 horizontal and multilateral wells over 10 years.

The contract for the drilling rigs and associated services covering the drilling of about 30 wells over the next six years has been awarded to the No 1 Drilling Company of Liaohe Petroleum Exploration Bureau. A four-year directional drilling contract was awarded to Halliburton Energy Services, while a three-year contract for drilling fluids and associated services was awarded to the Engineering Technology Institute of Changqing Petroleum Exploration Bureau.

A consortium comprising China Petroleum Engineering Company, Southwest Company and Sichuan Petroleum Engineering Construction Company signed an LOI for the EPC contract for the central gas processing facility. China Liaohe Petroleum Engineering has signed an LOI for the EPC contract for the inter-field pipeline infrastructure.

A second Shaan-Jing pipeline for transporting the gas to Beijing is already being built by PetroChina and is scheduled to go into operation by the middle of this year.

Shell has entitlement to about 50% of gas volumes over the 20-year project lifetime.

Idun and Skarv gas to go via Åsgard

The partners in Idun and Skarv in the Norwegian Sea – operated by Statoil and BP respectively – have opted to send their gas through the Åsgard pipeline to the Kårstø processing plant north of Stavanger. The announcement followed the decision to lay a new rich gas pipeline – Tampen Link – between the Norwegian and UK sectors of the North Sea. Tampen Link will run from Statoil's Statfjord field to tie into Britain's Far North Liquids and Gas System (Flags), which terminates at St Fergus in Scotland.

The annual capacity in the Åsgard pipeline to Kårstø will be upgraded by around 5% to 26bn cm in order to accommodate gas from Skarv and Idun. Due to come onstream in 2010, Skarv and Idun contain just over 38bn and 13.5bn cm of gas respectively. Skarv also holds 92mn barrels of liquids. Plans call for the new line to be laid next year and ready for operation by 1 October 2007, when Statoil will transfer the operatorship to Gassco.

MIDDLE EAST

The National Iranian Oil Company (NIOC) *has signed contracts for the development of South Pars Phases 17 and 18 with a consortium comprising Petropars (29%), Oil Industrial Engineering and Construction Company (OIEC; 50%), and Iran Offshore Engineering and Construction (IOEC; 21%). Plans are to produce 1mn t/y of LNG and 27mn b/d of gas condensate for export.*

RUSSIA/CENTRAL ASIA

China's CNPC and Uzbekneftegaz are *understood to be setting up a joint venture to develop 23 oil fields in Uzbekistan's Bukhara-Khivinsk oil and gas region.*

ASIA-PACIFIC

ExxonMobil (32.5%), BHP Billiton *(32.5%), Woodside Energy (21%) and Santos (14%) have signed a memorandum of understanding (MoU) to develop the Kipper gas field in Australia's Bass Strait. Reserves are put at 620bn cf of recoverable gas and 30mn barrels of condensates/LPGs. First gas is planned in 2009.*

Production recently resumed from the *Lufeng field operated by Statoil in the South China Sea, which was originally due to shut down for good in February 2004. However, new wells and innovative technology are helping to keep this development onstream from the Munin production ship until 2008. The company expects to boost the recovery factor on Lufeng from 32% to almost 40%.*

Apache reports that the Rose gas/con-*densate field in Australia has come onstream at a daily rate of 101mn cf of natural gas and 3,500 b/d of condensate. The field is part of the Harriet joint venture, which Apache operates with a 68.5% interest.*

East Timor is reportedly planning to *award its first oil and gas exploration licences in 2Q2006. A seismic survey off the East Timorese coast was completed in February.*

Brunei Shell Petroleum (BSP) has *awarded oil and gas SmartWell® intelligent completion specialist WellDynamics a five-year, multi-well contract for the provision of intelligent completions for the Champion West Phase III oil and gas development, offshore Brunei. The wells will be drilled*

Decline in UK output continues

UK oil production fell by 17% in March 2005, to reach 1,665,203 b/d, continuing the past year's trend of declining production, according to the latest Royal Bank of Scotland *Oil and Gas Index*. Gas production was also down by 10% on the year, at 10.591mn cf/d.

However, Tony Wood, Senior Economist with The Royal Bank of Scotland Group, states that these figures belie the 'significant upturn in investment and business optimism that has occurred in the North Sea this year'. Combined oil and gas production was down 13.5% on the year, at 3,529,751 boe/d.

Brent crude averaged $52.95/b in March, up $7.55/b on the month and up $19.23/b on the year.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Mar 2004	2,006,160	11,787	33.72
Apr	1,964,905	12,181	33.36
May	1,778,979	9,218	37.72
Jun	1,776,246	10,192	35.21
Jul	1,758,312	10,292	38.15
Aug	1,621,582	8,585	42.99
Sep	1,526,692	8,726	42.92
Oct	1,630,230	9,921	49.66
Nov	1,734,630	10,395	42.88
Dec	1,817,724	10,834	39.55
Jan 2005	1,700,031	10,891	44.24
Feb	1,716,160	9,781	45.50
Mar	1,665,203	10,591	52.95

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Repsol YPF looks to Latin American LNG

Repsol YPF has signed a memorandum of understanding (MoU) with US company Hunt Oil under which Repsol YPF will participate in the Peru LNG and Camisea projects.

Hunt Oil and SK Corporation currently own the Peru LNG project; the new agreement will bring Repsol in as a third participant. Peru LNG is to build, own and operate a liquefaction facility at Pampa Melchorita in Peru. The plant is expected to be operational in 2009 and will produce 4mn t/y of LNG for delivery to the west coast of North and Central America.

The Camisea fields will supply the natural gas for Peru LNG from block 88 and block 56 in central Peru. The MoU also contemplates Repsol YPF taking a stake in Transportadora de Gas del Peru (TGP), the company that delivers natural gas and natural gas liquids from the Camisea area through a trans-Andean pipeline.

Libya tops new ventures ranking

Libya leads the rankings in Fugro Robertson's 2005 New Ventures Survey by a significant margin. Algeria and Egypt also make the top three, giving North African countries a 'clean sweep'. However, the Middle East remains the most popular region as a whole, while the UK still manages fourth place, having taken the top spot for the past two years. Australia, at number five, remains a firm favourite. In contrast, Brazil only just scrapes into the top 10, and upward trends for the Former Soviet Union in 2004 have been reversed this year, with highest placed Russia at a lowly 15th position.

Indonesia (up four to number eight) and Yemen (up five places to number 11) have made significant gains, whereas the rankings of Kuwait (down 20 places to 41st) and Ukraine (down 18 places to 43rd) have plummeted.

The survey polls oil companies involved in E&P ventures outside North America and asks them to rate their level of interest in new ventures in 151 countries. The top 10 rankings in 2005 were: 1 Libya, 2 Algeria, 3 Egypt, 4 UK, 5 Australia, 6 Mauritania, 7 Oman, 8 Indonesia, 9 Equatorial Guinea, 10 Brazil and Iraq.

and completed from the CPDP-01 platform, which will be unmanned and fully remote-controlled after completion.

***A 50:50 Technip and J P Kenny joint** venture has been selected by operator Chevron as the front-end engineering and design (FEED) and engineering, procurement, construction and management (EPCM) contractor with respect to the upstream facilities for the Greater Gorgon project offshore north-western Australia. The project involves the development of both the Gorgon and Jansz fields, which will supply gas to a 10mn t/y LNG and domestic gas facility to be located on Barrow Island.*

LATIN AMERICA

***BP Trinidad and Tobago (bpTT; 40%** owned by BP, 30% owned by Repsol YPF) is to sell Teak, Samaan and Poui (TSP) oil fields off the south-east coast of Trinidad to Perenco and Neal & Massy Energy.*

AFRICA

***The Presidents of Nigeria and Sao** Tome are reported to have given formal approval for the award of five joint development zone (JDZ) blocks offered for bidding in 2004. Block 4 was won by Noble/ERHC, which holds a 60% stake, with Conoil (20%), Hercules Oil (10%), Godsonic Oil & Gas (5%) and Overt Oil (5%). Devon/Pioneer/ERHC won block 2, holding (65%) and partnered by Equator Exploration/ONGC Videsh (25%), A & Harmattan (10%), Foby Engineering (5%) and Momo Oil & Gas (5%). Andarko (51%) will act as operator of block 3, along with Devon/ERHC (20%), DNO/EER (10%), Equinox (10%) and Ophir/Broadlink, while an ICC/OEOC Consortium (75%) will operate block 5, along with ERHC (15%) and Sahara (10%). Operator of block 6 is Filthim-Huzod (85%), along with ERHC (15%).*

***Marathon Oil (30%) has announced** the Gengibre deepwater discovery in Angola block 32 – the company's ninth deepwater discovery in Angola and the third on block 32. The well tested at a rate of 4,724 b/d of oil.*

***BP has been awarded two new** shallow-water Nile Delta concessions – the Burullus and North El Burg blocks.*

***The Nigerian government is reportedly** offering 60 new oil blocks for the 2005 bidding round. A total of 15 of the new blocks are located in deepwater .*

New underground resources law unveiled in Russia

Russia's underground resources law (URL), the country's primary vehicle for oil and gas upstream projects, has long been criticised by Russian and foreign oil companies and investors alike. It is considered vague, open to subjective interpretation from Russian bureaucrats and does not require sufficient transparency at auctions for natural resources licences. These complaints prompted promises from various high-ranking officials, including the Minister of Industry and Energy, Khristenko, and the Minister of Natural Resources, Trutnev, that the URL would be revised and these problems addressed.

On 17 March 2005, the Russian government finally approved a new draft URL and sent it to the Duma for approval. However, while the draft URL does address many of the widely acknowledged faults, in the view of New York-based law firm Chadbourne & Parke, it 'institutionalises some of the equally negative aspects from a foreign investors perspective'.

'We view the draft URL as an improvement, but it is by no means good news for all present or potential investors in Russia's upstream sector,' says Shane DeBeer, a Partner at Chadbourne & Parke. 'Perhaps of most concern is the status of foreign investors under the new draft URL. Whilst the existing URL does not expressly restrict foreign participation, the new draft URL does. It explicitly provides that the exploration and development of newly licenced underground resources is restricted to Russian legal entities or, in very rare cases, Russian entrepreneurs.'

'Another important change proposed by the draft URL is that Russian companies forming a "group of persons" with foreign persons (individuals or entities) may be restricted from certain deposits,' adds DeBeer.

However, foreign investors are not entirely restricted from entering the market. Foreign investors may generally participate as a minority (up to 49%) shareholder in Russian entities bidding for licences.

Under the draft URL, the right to explore or develop underground resources may be granted either in the form of a licence or an agreement depending on the type of deposit and type of resource. An investor would enter into an agreement upon the successful conclusion of an auction or in accordance with a decision of the appropriate governmental authority. The draft URL does not set a maximum term for agreements and it also permits short-term agreements (of up to one year) without the requirement of an auction.

'We expect that in most cases of foreign investors, licences will be effectively replaced by agreements and this is significant development,' says DeBeer. 'Where licences are administrative instruments, agreements will be treated as rights covered by civil law. In effect, the draft URL converts hydrocarbon licences into leases of real property rights from the state that can be used as collateral to secure debt.'

In another key change, the draft URL provides that exploration and production rights will be awarded jointly, rather than separately as under the existing URL, thus eliminating the necessity for a company to bid for a deposit after already having spent significant funds on exploration.

Another beneficial change is the strengthening of the 'one key' system, whereby the investor/operator deals with a single governmental entity (the Ministry of Natural Resources) in negotiating the terms and entering into the agreement. 'In an improvement in transparency, nearly all such agreements will be granted on the basis of auctions, although the timing for bid packages has been significantly tightened,' adds DeBeer.

Under the agreement regime governed by civil law, the liability of the operator (user) is broader, with exceptions limited to illegal acts of the government or events of *force majeure*. At the same time, it appears that disputes in respect of agreements will be adjudicated exclusively in Russian courts rather than by administrative means.

'Based on the experience of many investors in dealing with other governmental agencies in Russian courts, this could well be a positive development,' comments DeBeer. 'Despite the reputation of Russian courts, it is a little-known fact that litigants against Russian governmental agencies (such as the tax inspectorate) frequently prevail and, in any event, judicial dispute resolution has the additional advantage of a measure of transparency and the right to appeal.'

UK

Amendments to the Control of Major Accident Hazards Regulations 1999 (COMAH) were to come into force on 30 June 2005. The full text of the amendments can be seen at **www.legislation.hmso.gov.uk/si/si2005/0051088.htm**

Andy Watson, Energy Manager at BAA *Heathrow, has been awarded the annual Energy Manager of the Year award, presented by the Energy Institute at the Gala Dinner of this year's annual Energy Management Conference and Exhibition (Nemex).*

EUROPE

BG Group is taking full ownership of *the Brindisi LNG import terminal in Italy, having acquired Enel's 50% stake in the project for €17mn in cash and a deferred, contingent sum of about €27mn.*

Shell and Dutch energy company Nuon *have signed the final contracts for what is claimed will be the first Dutch offshore wind farm, due to be commissioned in 2006. A total of 36 wind turbines with an overall capacity of 108 MW will be constructed.*

Eni and Algeria's Sonatrach have *reached agreement on the expansion of the Trans Tunisian Pipeline Company (TTPC) pipeline carrying natural gas from Algeria to Sicily through Tunisia. The agreement sets an increase of up to an additional 3.2bn cm/y of transport capacity starting from 2008, and up to a further 3.3bn cm/y starting from 2012. The current capacity of the import pipeline from Algeria is around 27bn cm/y and will reach 33.5bn cm/y in 2012.*

Eni reports that the Trans Austria *Gasleitung (TAG) pipeline, which transports Russian gas to Italy through Austria, is to be expanded by at least an additional 3.2bn cm/y, up from 32.5bn cm/y, by 2008.*

NORTH AMERICA

Repsol YPF and Irving Oil are to *develop an LNG import and regasification terminal in Saint John, New Brunswick – the first LNG regasification plant on the east coast of Canada. The Canaport LNG terminal will initially be capable of delivering 10bn cm/y of LNG and is due onstream in 2008.*

Sakhalin signs fifth LNG contract

The Sakhalin II project is to supply an additional 0.2mn t/y of LNG to Toho Gas Company for 20 years. The deal follows an earlier heads of agreement (HoA) that was signed in March 2004 for the supply of 0.3mn t/y of LNG to Toho. In addition to the increased volumes, Toho Gas has also decided to accelerate the start of LNG deliveries by one year to 2009.

The project also recently signed a contract to supply 0.42mn t/y of LNG to Tohoku Electric Power for 20 years, from 2010. It is also to supply up to 0.21mn t/y of LNG for 20 years to Hiroshima Gas. In comparison with other contracts that normally use LNG tankers in excess of 125,000 cm capacity, Hiroshima Gas is planning to use its newly built ice class LNG vessel with a capacity of about 20,000 cm to transport the LNG to its own receiving terminal in Hatsukaichi.

LNG will be supplied from Sakhalin Energy's 9.6mn t/y LNG plant, which is under construction at Prigorodnoye at Aniva Bay on the southern tip of Sakhalin. This will be the first LNG plant to be built in Russia. The plant will have two gas liquefaction process trains, each with a capacity of 4.8mn t/y.

The shareholders in Sakhalin Energy are Shell (55%), Mitsui (25%) and Diamond Gas (20%; parent company Mitsubishi).

Various other sales deals have already been agreed:

- Tokyo Gas, 1.1mn t/y, starting from project start for a period of 24 years.
- Tokyo Electric, 1.5mn t/y, starting from project start for a period of 22 years.
- Kyushu Electric, 0.5mn t/y, commencing 2009 for a period of 22 years.
- Toho Gas, 0.3mn t/y, commencing 2010 for a period of 24 years.
- Baja Mexico (Shell Eastern Trading), 1.6mn t/y, starting from project commencement for a period of 20 years.
- Korea Gas Corporation, 1.5mn t/y, commencing January 2008 for a period of more than 20 years.

Phase 1 of the Sakhalin project has been producing oil from the Vityaz complex offshore Sakhalin since July 1999. The Vityaz complex consists of the Molikpaq production platform, a single anchor leg mooring buoy and the Okha floating storage and offloading unit, and is located on the Astokh feature of the Piltun Astokhskoye (PA) reservoir offshore Sakhalin.

Phase 2 of the Sakhalin II Project is thought to be the biggest single integrated oil and gas project ever undertaken. It entails the further development of the PA field (an oil reservoir with associated gas) and the development of the Lunskoye field (a gas reservoir with associated condensate). Apart from the LNG plant, the project also calls for another oil and gas production platform on the PA field and a new gas platform on the Lunskoye field.

An onshore processing facility is being built to separate gas and condensate from the Lunskoye field. Pipelines will transport the oil and gas more than 800 km to an oil export terminal and the LNG plant at Prigorodnoye on the southern end of Sakhalin Island, which remains largely ice-free year round. The Phase 2 project will also enable year-round production from the Molikpaq platform.

Year-round oil production is expected in 2006, and deliveries from the new LNG plant are planned to commence end 2007.

News from the European Union

Cooperation between the European Union (EU) and Russia is to intensify regarding energy infrastructure projects of joint interest, under a detailed 'road-map' approved in Moscow, writes *Keith Nuthall.* Russian President Vladimir Putin, European Commission President José Manuel Barroso and EU Council President Jean-Claude Juncker signed the deal, which also highlights improving the safe transport of energy products 'by pipeline, rail and sea'. This work will build on the existing EU-Russia Energy Dialogue programme. Brussels will also help Russia's planned 'gradual and progressive reform' of its gas sector to 2020.

The deal comes as the European Bank for Reconstruction and Development (EBRD) has released two plans to help Russian company Lukoil. It is planning to lend subsidiary Lukoil Overseas Holding $110mn to develop the offshore Shakh Deniz gas and gas condensate field in Azerbaijan, drilling nine wells and processing onshore. And it plans to lend $70mn to help fund construction of the South Caucasus Pipeline, transporting gas from Azerbaijan to Turkey, in which Lukoil has a 10% stake.

Elsewhere in Azerbaijan, the World Bank may lend $15.50mn to AzInvest Property to develop a 2.6 hectare Baku site into a $42.60mn office complex leased by BP Exploration (Caspian Sea) for developing the Azeri, Chirag and Gunashli oil fields, the Shakh Deniz field and the Baku-Tbilisi-Ceyhan and South Caucasus Pipelines.

Meanwhile, the European Court of Justice (ECJ) has told Italy to scrap a rule suspending voting rights exceeding 2% for gas company shares held by (possibly foreign) public bodies. The ECJ said it was an illegal restriction of trade.

ConocoPhillips has entered into a joint development agreement with Mitsubishi's wholly owned subsidiary Sound Energy Solutions (SES) to develop a proposed LNG import terminal in the Port of Long Beach, California. The proposed terminal would have the capacity to import approximately 5mn t/y of LNG and is expected to be completed in 2009.

RUSSIA/CENTRAL ASIA

The Baku-Tbilisi-Ceyhan (BTC) oil pipeline project has been officially inaugurated. The 1,770-km pipeline will carry up to 1mn b/d of oil from the BP-operated Azeri-Chirag-Gunashli (ACG) field in the Caspian Sea to the eastern Mediterranean port of Ceyhan, bypassing the heavily congested Bosphorous Straits. Depending on negotiations between the governments in Tiblisi and Astana, BTC capacity could be increased by 80% to take oil from Kazakhstan.

TNK-BP has approved expenditure of $136mn for the 'Early Gas' phase of the $1.1bn Kovykta project in Eastern Siberia that will deliver Kovykta gas to industrial customers in Sayansk, Usolie-Sibirsk, Angarsk, and Irkutsk.

ASIA-PACIFIC

Foster Wheeler has been awarded an engineering, procurement and construction management (EPCm) contract with Woodside Energy (operator) on behalf of the North West Shelf Venture following final approval by its six joint-venture participants to invest A$2bn on a Phase V LNG expansion project to be built at Karratha, Western Australia. Foster Wheeler is leading a joint venture with WorleyParsons Services to execute this project, which involves the addition of a fifth LNG processing train with a production capacity of 4.2mn t/y to the existing 11.7mn t/y LNG complex.

Sinopec is reportedly planning to spend some $604.6mn on the first phase of construction of an LNG port, terminal and pipeline in the city of Lianyungang in China's Jiangsu province. The second phase involves a gas-fired power plant, designed to meet local demand.

Petronas will supply up to 145mn cf/d of gas to PLN's Tambak Lorok power plant in the Central Java province for a period of up to 10 years. The gas will be supplied from the Kepodang field within the Petronas-operated Muriah block.

Major UK wind farm proposal

A consortium comprising CORE, E.ON UK Renewables and Shell WindEnergy has submitted consents and planning applications for the London Array offshore wind farm project. If built, the wind farm could generate up to 1,000 MW of renewable electricity, enough for more than 750,000 homes, while eliminating emissions of up to 1.9 t/y of carbon dioxide. In addition, it could make up to 10% of the UK government's 2010 renewables targets. The full development, costing up to £1.5bn, will require up to 270 wind turbines connected into the National Grid's transmission system in Kent. The turbines would be located in the outer Thames Estuary, more than 20 km offshore and equidistant from the coasts of Essex and Kent.

If consents are granted, the construction programme envisages London Array being built in up to four phases. The first phase would be commissioned in 2008, and it is hoped that all phases would be complete by 2010/2011.

Equatorial Guinea LNG stakes sold

Mitsui and Marubeni are to acquire for an undisclosed sum an 8.5% and 6.5% interest, respectively, in the Equatorial Guinea LNG project. Marathon will now hold a 60% stake in the project, with GEPetrol, the national oil company of Equatorial Guinea, holding 25%. GEPetrol is selling a 13% interest that it is obtaining from Marathon by exercise of a purchase right as a shareholder in the LNG project company. In addition, Marathon is selling a 2% interest to Mitsui.

The Equatorial Guinea LNG project has a contracted off-take rate of 3.4mn t/y for 17 years, although the plant is expected to have the ability to operate at higher rates and for a longer period of time. Natural gas will be purchased from the Alba field participants, Marathon, Noble Energy and GEPetrol. The LNG will be sold to BG Gas Marketing under a 17-year purchase and sale agreement beginning in late 2007.

Approval for gas-turbine propelled LNG ships

Lloyd's Register has issued an approval in principle of GE Energy's LM2500-based, gas turbine propulsion system for LNG ships. Gas turbine propulsion systems have been widely used on naval and cruise ships, but are new to LNG vessels. The approval in principle gives GE Energy a high level of confidence that the marine industry will embrace its gas turbine propulsion system design as a viable alternative to traditional propulsion methods for the next generation of large LNG tankers.

Traditionally, LNG tankers have been powered by steam turbine engines, but as larger vessels are built to accommodate the growing demand for natural gas, standard propulsion systems are beginning to demonstrate certain shortcomings, such as low efficiency, high emissions, lack of availability of steam-qualified crew and the high costs associated with scaling steam turbine systems for larger tankers. GE Energy believes its LM2500-based, gas turbine propulsion system addresses these issues and offers many other benefits, including the ability to burn the boil-off gas from LNG containment systems in a natural, reliable and redundant manner. GE Energy also believes its gas turbines provide improved maintainability over other systems.

Harvesting energy from sea swell

Scottish-based Ocean Power Delivery (OPD), in which Hydro of Norway has invested, has signed an order with Portuguese energy company Enersis to build what is claimed will be the world's first commercial wave farm to harvest electricity from sea swells. Located some 5 km off Portugal's northern coast, near Póvoa de Varzim, the €8mn project will use three OPD-developed Pelamis P-750 wave power generation units, capable of producing some 2.25 MW of electricity. Planned for completion in 2006, the farm will initially supply some 1,500 Portuguese households with electricity and displace more than 6,000 tonnes of carbon dioxide emissions that would otherwise be produced by conventional hydrocarbon-fuelled power plants.

A letter of intent has also been issued to order a further 30 Pelamis machines (for a total 20 MW) before the end of 2006, subject to satisfactory performance of the initial project phase. If all goes well, many additional sites producing up to a total several hundred MW could be developed along the coast.

UK

UK Transport Secretary Alistair Darling *has unveiled a plan to tackle traffic congestion by using a satellite-based road pricing system. The satellite charges would replace fuel duty and road tax, thereby acting to influence car use rather than mere car running costs as at present.*

Maxol is reported to have acquired 13 *Esso service stations in Northern Ireland and is planning a two-year, £5mn modernisation programme for the sites. The deal brings the number of Maxol fuel outlets in the province to 41.*

BP and Marks & Spencer have entered *into a relationship to trial eight Marks & Spencer Simply Food concepts in BP Connect forecourt sites in the UK, starting in autumn 2005.*

The London Energy Brokers' *Association (LEBA) has launched a new benchmark index for the energy markets – the LEBA Carbon Index for trades in EU emissions allowances. The aim of this independent benchmark index is to contribute towards a more transparent, liquid, traded market in emissions allowances.*

Centrica has agreed to sell British Gas *Connections Limited (BGCL), its licensed gas transporter business, to Kellen Venture for £90mn.*

EUROPE

Vopak has signed a long-term contract *with Q8 Aviation for the storage and logistics handling of JetA-1 by Vopak's oil terminal in Rotterdam. The initial volume to be handled will be around 1mn t/y, this is expected to rise in future years given the increasing geographical imbalance between the supply and demand for JetA-1.*

Centrica has agreed to acquire Oxxio, a *Dutch energy supplier, for £93mn. Oxxio currently has around 400,000 electricity and 140,000 gas accounts, and, following full market liberalisation in July 2004, is now acquiring around 20,000 energy accounts per month.*

Norway's Statkraft and German *energy company Mark-E are to jointly build a 400-MW gas-fired power plant in Germany that is scheduled to be commissioned in the autumn of 2007. The facility is expected to have an efficiency of at least 57.5%.*

BBL terminal contract for Amec

Amec has been awarded a £25mn contract by Shell UK to design, engineer and deliver a new gas reception facility at the Bacton natural gas terminal, Norfolk, as part of a major pipeline project by Balgzand Bacton Pipeline Company (BBL) to transport gas from the Netherlands to the UK. Shell is responsible for overall project management and commissioning of the new facility, which will be owned by BBL VoF, an international consortium of gas transmission companies. The facility will consist of four process trains featuring 5.3-MW heaters, filtration, flow control and metering systems, with a central control and safety systems building and a 450-metre long pipeline tie-in to the National Grid Transco transmission network.

First gas is expected onstream by the end of 2006. Gas will be transported to the reception facility through BBL's 235-km pipeline that runs under the North Sea from Balgzand on the Dutch coast to Bacton. The pipeline will allow the import of high quality gas from Europe to help secure energy supply to the UK as reliance on imported gas increases. At full capacity it will be able to supply up to 13% of the UK demand for gas.

Trailblazing US hydrogen super highway

Imagine traveling from New York to Los Angeles by car in 10.5 hours, while the rail system you are running on is producing enough extra hydrogen to power 70% or more of the country's entire energy demand at no extra charge. That is the aim of a proposed 'hydrogen super highway' – called the 'Trailblazer' – across the US that runs on clean-burning hydrogen-powered magnetic levitation (MagLev) rails, transporting cars, freight and people at up to 250 mph. If developed, it is claimed that Trailblazer has the potential to produce enough excess hydrogen from its built-in solar panel arrays to power all of the US, with near zero environmental consequences. The plan is being promoted by Interstate Traveler Company (www.interstatetraveler.us**), supported by ACSA (the American Computer Scientists Association Inc –** www.acsa.net**).**

The hydrogen fuel provided by the Trailblazer for general use is called Hydroline™ – a slightly compressed form of hydrogen obtained when electrons from a solar panel are fed to ordinary water. It is cooled and stored within the conduit that is part of the rail system. When needed, it is fed to fuel cells for electricity production or to Hydroline™ powered internal combustion engines which burn the fuel cleanly, yielding only water and heat.

According to ACSA, which has studied Interstate's plans in depth: 'Trailblazer advances a truly revolutionary technology solution – one which has broken down the barriers to a ready supply of cheap, hydrogen energy for the future clean energy economy of America... If it works, its hydrogen from a solar production system could reduce the entire cost of energy in America by \$100bn/y by the end of its first construction year, \$200bn its second year, \$300bn the third, \$400bn in the fourth. If the company's estimates are correct, by the end of the fifth year the Interstate Traveler's built-in solar to hydrogen converters could be paying for nearly all of America's energy needs... It could spell an end to dependency on non-sustainable energy sources like oil and coal, and an end to US dependency on foreign fuel, which can be redirected to making lubricants, chemicals and plastics.'

UK firms open carbon accounts

Firms covered by the EU Emissions Trading Scheme (EU ETS) recently opened their UK carbon accounts after publication of allowances for installations covered by Phase I of the scheme.

Emissions trading started in the UK with the UK Registry becoming operational, allowing operators participating in the scheme to access their allowances.

The scheme is set to help reduce carbon dioxide (CO_2) emissions by around 65mn tonnes (around 8%) below projected emissions of the installations covered by the scheme over the next three years.

The Emissions Trading Registry is web-based, and records CO_2 allowances held in firm accounts. It allows allowances to be transferred to other accounts both within the UK and in other participating countries.

A total of 12 other countries have been licensed to use the UK's Registry software – Denmark, Estonia, Finland, Hungary, Ireland, Italy, Latvia, Lithuania, Slovenia, Sweden, the Netherlands and Norway. Four of these (Denmark, Finland, Sweden and the Netherlands) have already started trading.

Further information is available at **www.defra.gov.uk** and **www.environment-agency.gov.uk**

RAG, Wingas and Gazexport are planning to convert the Austrian Haidach gas reservoir into underground gas storage (UGS) at a cost of e250mn. The maximum working volume of the UGS is expected to be 2.4bn cm of gas – equivalent to about 30% of Austria's total annual gas consumption. Operations are slated to begin in 2007.

Norsk Hydro is to sell its Swedish power trading company Hydro Kraft to the Swiss energy company EGL for an undisclosed sum.

BP and NOVA Chemicals have signed binding agreements to merge their European styrenic polymers businesses into a 50:50 joint venture – NOVA Innovene.

NORTH AMERICA

ExxonMobil Research and Engineering Company (EMRE) reports that Motiva Enterprises – owned by affiliates of Shell Oil Company and Saudi Refining – will construct a third lube train applying ExxonMobil's catalyst technology at its base stock complex in Port Arthur, Texas. The new unit will make Motiva's Port Arthur facility the world's largest Group II base oil plant and enable it to produce an additional 15,000 b/d of high quality base stocks. This third application will boost Motiva's total Group II production to more than 13mn b/y at Port Arthur.

MidAmerican Holdings is reported to have reached an agreement with Scottish Power to acquire its US-based subsidiary PacifiCorp. The acquisition, valued at $9.4bn, would form a top-tier global energy company serving 6.6mn customers worldwide.

A series of failures by BP personnel before and during the startup of the isomerisation (ISOM) process unit in the Texas City refinery led to an explosion and fire which claimed the lives of 15 workers and injured more than 170 people, according to BP Products North America's interim fatal accident investigation report made public in mid-May. The report can be viewed at **www.bp.com**

MIDDLE EAST

Innovene, BP's petrochemicals and refining subsidiary, and Delta International, a leading Saudi-owned independent development company, have signed a memorandum of understanding (MoU) for a major invest-

Motorists need to be more cost-saving aware

Most car buyers are unaware of the lifetime cost savings of purchasing more fuel-efficient, 'climate friendlier' cars according to recent research carried out on behalf of the Low Carbon Vehicle Partnership (LowCVP). The average motorist significantly underestimates the total cost of owning a car and many drivers are unaware that vehicle excise duty (VED – the annual 'road tax') rates are less for cars producing lower carbon dioxide (CO_2) emissions. Furthermore, many car buyers assume there is little difference in fuel efficiency (miles per gallon) between cars of the same type. Consequently, motorists are more likely to be influenced by immediate considerations such as the cost of purchase and driving performance rather than by fuel economy and environmental issues.

The LowCVP commissioned Ecolane to carry out the research as the first stage of a two-part process, bringing together existing information from a range of sources from both within and outside the partnership. The second stage will include original research intended to build and elaborate upon the findings of the initial study. The outputs of both stages will be shared amongst partnership members to help inform companies' marketing strategies and provide some pointers for government policies.

On their own, the report says, pure environmental considerations currently play little or no part in determining buyers' decisions. This is despite the fact that other research shows that the environmental issues of most concern to the public over the next 20 years are traffic, air pollution and climate change. The initial research indicates that financial incentives are necessary, but not sufficient in themselves to stimulate pro-environmental consumer behaviour in terms of car choice. Car buyers also need to have a positive attitude about low carbon models. However, there is evidence that consumers currently have a very poor understanding of low carbon and fuel-efficient vehicle options.

The report does, however, recommend that there are some 'early adopter' groups of car buyers – notably certain company car fleets, who are likely to be more responsive to marketing activities designed to promote sales of low carbon cars.

Earlier this year, the LowCVP announced the introduction of a colour-coded fuel economy label as a result of a voluntary industry-wide agreement with stakeholders. The new label, which will appear in all new car showrooms from September this year, will provide car buyers with more accessible information about a car's environmental performance and the close link between lower CO_2 and lower costs.

A copy of the report can be dowloaded from www.lowcvp.org.uk/resources/reportsstudies/

An electricity supply strategy for the UK

Investment in low-carbon, large-scale sources of electricity – from tidal to nuclear to clean coal – are key to future energy policy in the UK, recommends a new report published by the Council for Science and Technology (CST). The report – entitled *An Electricity Supply Strategy for the UK* – is available at **www.cst.gov.uk**

The report calls for a new strategic approach in response to changing energy sources and the challenge of climate change. Public engagement also has a key role to play in addressing the broader issues, including the different options, to help government make more responsive and timely decisions.

The CST, the government's top-level advisory body on science and technology policy issues, has made a number of recommendations in the report addressing the key energy policy issues, which include:

- Immediate investment in large-scale, low-carbon, energy generation facilities to meet the government's carbon dioxide reduction targets.
- Keeping the nuclear option open and placing more emphasis on carbon sequestration and tidal power.
- Government investment in R&D should be aimed at new and renewable fuel sources, energy management, storage and improving the supply and training of skilled workers in the UK.
- Development of the transmission network, its protection mechanisms and metering systems to facilitate distributed and diverse generators, ranging from commercial to domestic units; and to address the regulatory issues arising from this form of generation.

ment in Saudi Arabia's petrochemical sector. It is hoped that the first plants could be commissioned in late 2008.

Dubai Holding and the New York *Mercantile Exchange (Nymex) have announced the formation of the Dubai Mercantile Exchange (DME) – a joint venture to develop the Middle East's first energy futures exchange. It is expected that the DME, which will house both open outcry and electronic trading platforms, will initially trade sour crude and fuel oil on a transparent platform for price discovery. The DME is expected to open for trading in early 2006.*

RUSSIA/CENTRAL ASIA

According to the Prime Minister of *Kazakhstan, Danyal Akhmetov, the republic is to develop its Aktau port capacity on the Caspian Sea to handle increased volumes of oil. In addition, the government has approved a proposal by state-owned KazMunaiGas to construct a sea port at the town of Kuryk, located 76 km south of Aktau. According to Uzakbai Karabalin, President of KazMunaiGas, intends to link-up to the Baku-Tbilisi-Ceyhan (BTC) pipeline through this new port. The Kazakh Transport Ministry is also planning to construct a railway connecting Kuryk to the country's main rail infrastructure, including the planned Trans-Asian link will run from China into Europe and offer an alternative to the Trans-Siberian railway. At present, 8mn tonnes of Kazakhstan's total yearly production of between 40mn and 45mn tonnes transits via the Caspian. The Kuryk seaport is expected to be operational by the time the Kashagan oil comes onstream in 2007–2008.*

ASIA-PACIFIC

The Bangladeshi government is report- *edly planning to convert all public sector vehicles to run on CNG (compressed natural gas) by 2005 in a bid to reduce imports of petroleum products, which currently cost some $1.3bn/y.*

Castrol, the lubricant brand of BP, and *Dong Feng Group are to form a joint venture company to supply lubricants to the growing Chinese market. The new company, Dong Feng-Castrol Lubricant Co, will be based in Wuhan, in Hubei Province, and is the first Chinese-based lubricant equity joint venture between a global lubricant major and a leading Chinese automobile manufacturer.*

Lukoil expands US forecourt network

Lukoil is planning to expand its presence in the US fuel retail market, CEO Vagit Alekperov is reported to have stated at a recent press conference in New York. The company currently sells some 8mn t/y of oil products in the US.

Lukoil operates 2,000 service stations in the north-east US – approximately 30% of its total network in the country. It is currently revamping and rebranding sites that it bought from Getty and Mobil, in a programme expected to take three years to complete.

According to Alekperov: 'This should have a positive effect on the company's financial activities, since right now we have to pay ExxonMobil almost $25mn/y for the use of the Mobil brand at our gas stations.'

In 2004 Lukoil purchased 795 gas stations from ConocoPhillips in New Jersey and Pennsylvania states.

Fuel cards – fuel for thought in Europe

New research from independent market analyst Datamonitor reveals that, even in markets where fuel penetration is high, there are a significant number of motorists in both the commercial road transport (CRT) and fleet segment who have never had a fuel card.

'Across Western Europe, 17% of commercial fuel volumes are paid for with cash and 23% are purchased with a credit card. Since the advantages of cash payment are dwarfed when compared with the benefits and services of a fuel card, this group of non-subscribers are the easiest targets for fuel card providers hoping to acquire new business,' states the analyst. 'Companies with a fleet opting for credit card payment are, however, much harder to convince given the versatility and competitive rates unique to this method of payment. Nonetheless, providers that employ direct mailing and telesales in tandem and forge relationships with associations and other reputable enterprises are best positioned to exploit the enormous untapped potential offered by this segment of fuel card novices.'

Deloitte partners EI Awards

The Energy Institute (EI) is pleased to announce that professional services firm Deloitte has become the official partner of the annual EI Awards.

The awards acknowledge outstanding new initiatives, good practice, excellence and innovation in the energy industry. This year's winners will be presented with their trophies at a Gala Dinner on 25 November 2005 at The Savoy Hotel, London, UK, which will be hosted and presented by explorer Sir Ranulph Fiennes OBE.

Deloitte lead Energy Partner, Carl Hughes, says: 'These awards highlight the biggest and best achievements within the global energy industry today and we are hugely supportive of them. We look forward to working with the Institute through our partnership and to championing innovation and excellence in the sector.'

Lawrence Slade, Business Development Director at the Energy Institute, comments: 'We are delighted to welcome Deloitte as the official partner to these annual EI Awards. Celebrating the best of the energy industry, we are also extremely grateful to our award sponsors Amec, BG Group, ExxonMobil, KPMG, Norman Broadbent, Shell, TNK-BP and Total, for their commitment and support to acknowledging merit and achievement amongst energy professionals.'

For further details about the EI Awards, visit **www.eiawards.com** or contact Jacqueline Warner, Events Organiser, on t: +44 (0)20 7467 7116 or e: **jwarner@energyinst.org.uk**

Men onboard

It is becoming apparent that the greatest threat to the huge expansion in the global LNG business is not the availability of terminal or shipping capacity but the lack of suitably qualified and experienced seafarers. Training schools and ship managers are looking at ways of overcoming the problem.

The growth in the LNG tanker fleet is simply staggering. Compared to an existing fleet of some 170 ships, there are currently more than 100 on order. Operators and charterers alike are increasingly concerned that there will not be enough qualified crews to man these ships as they arrive from the yards over the next three or four years. The topic was high on the agenda at the Gastech conference in Bilbao in March, where some solutions to offset the problem were offered by representatives of ship management companies and training providers.

Ray Gillet of L3 MPRI Ship Analytics – himself a former LNG tanker master – said that there is a serious shortage of skilled personnel both for shipboard operations and for offices ashore. Indeed, he warned: 'We will soon get to the point when we won't be able to man the fleet.'

The problem is that the LNG fleet is small compared to other maritime sectors so the resource base has traditionally been small. But there has been an increase in fleet size of more than 60% in the past five years – and there is more to come.

Captain Simon Pressly of ship manager Dorchester Maritime Ltd (DML) had a slightly different perspective. He noted that the rate of increase in the LNG fleet has been fairly steady. Moreover, as there are between 35 and 40 companies involved in operating LNG tonnage, the 'pain' of taking on new ships has been evenly spread. The relatively long lead times involved in LNG tanker construction also indicate that growth should be able to be managed.

However, Pressly agreed that there is a general shortage of deck officers with gas experience and engineers with knowledge of steam propulsion. Almost all existing LNG tankers – and most of those on order – feature steam engines, since they make it easy to use the gas that boils off the cargo. However, such engines have been phased out in the rest of the merchant marine and engineering officers now need to be trained specifically. While some operators are beginning to look at alternatives to steam propulsion, these too will bring difficulties. Gaz de France has ordered three ships with dual-fuel diesel-electric propulsion (see p14), but these still use boil-off gas as part of the fuel input. Others are looking at onboard reliquefaction to return boil-off gas to the cargo tanks, but such an arrangement brings yet another piece of specialised kit for engineers to deal with.

There are other factors hindering recruitment and crew deployment, Pressly said. High on the list is the sheer monotony of operating LNG tankers. During normal conditions of carriage the LNG cargo is inert and deck officers have little to do. Load ports are often in remote or inhospitable locations and discharge ports – especially in the US – are increasingly bound around with security regulations. There is, therefore, little opportunity for crews to leave the ship during port calls. Good rates of pay have to be offered to attract and retain shipboard personnel.

In addition, Pressly noted, charterers demand that crews have prior experience of working on LNG ships. Obviously there is a finite pool of such personnel, and senior officers are being tempted ashore by demand for superintendents. Managers need to spread their LNG-experienced crews around their ships and allow personnel with experience from related types of ship – particularly larger LPG carriers and VLCCs (very large crude carriers) – to develop LNG expertise by working alongside them. However, Gillet said, there is the risk that a skill-based incident will occur and have an adverse effect on public confidence in LNG.

Safety standards

The LNG industry is very concerned about safety and is keen to maintain the excellent record it has in this regard, particularly as a way of offsetting public opposition to LNG import terminals in the US. However, Pressly said, the shortage of quality crews for LNG ships raises a number of severe threats. Managers can be tempted into short-term thinking, stealing staff from other operators rather than investing in bringing their own staff up to the standards required – and seafarers can use this type of thinking to improve their own wage levels. If there are insufficient suitably qualified personnel available, then there is pressure to lower the standards required.

This approach is particularly acute among ship operators and managers arriving in the LNG sector for the first time, as they have no established pool of LNG-experienced personnel to draw on.

Pressly pointed out that it can take 10 years to train a cadet up to master or chief engineer level. Clearly the shortage of qualified LNG personnel cannot be addressed by recruiting young people to the industry. Rather, he explained, personnel with experience in related sectors can be cross-trained – but this runs up against the problem of the acceptance by charterers of inexperienced personnel.

This insistence on experienced crew members fails to acknowledge that personnel who have worked on elderly LNG tankers – of which there are plenty still in operation – may find it hard to adjust to working on a new ship, since levels of automation have increased significantly in recent years. Indeed, deck officers transferring from new large LPG tankers might well be more effective in operating newer LNG ships.

The solution proposed by both speakers involves both a structured training schedule for crew coming from other ship sectors and the acceptance by charterers that this approach provides the level of safety they demand.

Pressly said that there will need to be four elements to any training programme:

- Mandatory STCW (standards of training, certification and watchkeeping) requirements imposed by flag states.
- Company-specific and optional training, including management systems.

DML has taken practical steps to help train deck officers and, in cooperation with the Ilawa training school in Poland, has developed a ride-on model LNG carrier, dubbed the *Dorchester Lady* (see p16)

- LNG-specific training, including steam plant.
- LNG carrier familiarisation.

Gillet's proposed solution was more outcome-based. While he agreed on the basics of STCW and company management systems, he said there are two particular areas that require longer, more intensive and, in some cases, costly training and examination – cargo handling and steam plant operation.

As regards cargo handling, Gillet said, there is a large pool of personnel within the broader shipping industry with significant experience in handling bulk liquids and gases and able to meet the regulatory requirements for service on LNG vessels, despite not having any direct experience with LNG. Some of these personnel are keen to transfer to LNG because of the better working conditions and pay, he suggested. The specific skills required to allow them to safely undertake LNG cargo handling operations can be provided easily by an appropriate training course.

Training for the job

The situation as regards steam plant operation is more difficult, Gillet admitted. There are very few engineers outside the LNG sector who hold 'steam tickets' and those that do are mostly of an age when they are not willing to continue serving at sea. There is a pool of engineers who have dual diesel and steam certificates and meet flag state requirements, but most do not have 'hands-on' experience with steam plant that is needed by operators. Again, appropriate training can help, but the number of people involved is small. Therefore, the LNG sector must seriously address the need to convert existing diesel engineers into steam engineers.

This apart, Gillet said, there is an urgent need to train deck and engineering officers who have, in addition to the appropriate regulatory certification, a detailed knowledge, understanding and practical skill that allows them to be placed in junior or senior positions on LNG vessels with minimal risk in the shortest possible time.

In particular, Gillet criticised charterers' insistence on time at sea on LNG ships being a defining factor in judging the qualification of crew members. The shipping industry needs to take a new approach and look at the end requirements, he said, not merely the gaining of certificates. Standards need to be carefully defined, against which ability can be measured. This will be difficult, he admitted, but it would set a benchmark, avoid arguments, help new entry personnel and allow suitable candidates to be fast-tracked. The onboard assessment of senior personnel is clearly not practical and he recommended wider use of simulators for both training and assessment.

This approach is not exactly revolutionary for the gas tanker sector. The mandatory training requirements are quite limited in scope, relating mainly to compliance with STCW and the ISM (International Safety Management) Code. Training specific to gas tankers is defined largely by representative bodies, primarily SIGTTO (Society of International Gas Tanker & Terminal Operators), which has established safety levels and through which charterers can make their expectations known.

However, for standards set by the industry to be useful they need to be recognised and agreed throughout

continued on p16...

LNG vessels – the next generation

Gaz de France Energy

A new generation of ships has recently been ordered for the $12bn Qatargas II project to transport LNG to the UK. These vessels will be 40% larger than their predecessors and will feature plant for reliquefaction of 'boil-off' gas, together with slow-speed diesels for propulsion, for the first time. These orders came as construction of the world's first diesel-electric LNG carrier was nearing completion, prior to sea trials in December 2004. Jeff Crook *reports.*

Prior to this diesel development, the entire world fleet of around 175 LNG carriers was propelled by steam – a solution regarded as obsolete by all other sectors of the shipping industry. While steam plant provides a reliable form of propulsion, and an effective method for disposal of the gas which 'boils-off' from the cryogenic cargo, it is inefficient.

The latest diesel-powered vessels will use less fuel – marine diesel engines offer thermal efficiency of around 50%, compared to around 30% for steam turbine plant. However, reliability will be an issue as diesel engines require some routine maintenance and can suffer breakdown.

For safety reasons, it is unacceptable for an LNG carrier to loose its propulsion, even in port, unless it is completely purged of flammable gas. To achieve this, LNG carriers have traditionally been equipped with a pair of boilers to provide high-pressure steam for turbines, which are inherently reliable machines. A steam plant like this can provide uninterrupted propulsion for a period of more than two-years, without difficulty. Two-year service is quite adequate, because the vessel will need to be taken out of service for dry-docking to meet 'class' survey rules after that period.

To match this level of reliability and availability, diesel propulsion needs to incorporate redundancy. This has been achieved in two different ways. The first approach is for all power and propulsion to be provided by four diesel engines, in a diesel-electric configuration. The second approach is to provide two slow-speed engines for propulsion, with each engine driving its own propeller, via a clutch. This latter approach has been adopted for the Qatargas II ships.

Diesel-electric gains support

Thought also needs to be given to the safe disposal of 'boil-off' gas. As with the steam vessels, the 'boil-off' gas provides most of the fuel for power and propulsion on the 74,000 cm *Gaz de France Energy* (see *Petroleum Review*, July 2002), the world's first diesel-electric LNG carrier. The dual-fuel engines will also use a small quantity of diesel oil as pilot fuel. This arrangement provides a safe method of disposing of the 'boil-off' gas while the ship is underway, while excess 'boil-off' gas (above that needed as fuel) will be burned in a 'thermal oxidiser when power demand is low, when the vessel is in port.

The benefits of this configuration derive partly from the higher fuel efficiency of diesel engines, since less vapourised LNG, or diesel oil, is needed to supplement the 'boil-off' as fuel. However, further benefits derive from the compact nature of the machinery in comparison to steam plant, leading to higher cargo capacity.

These benefits have led to a similar diesel-electric configuration being specified for two 153,500 cm capacity ships for the Gaz de France fleet, and up to eight 155,000 cm capacity vessels for BP. When BP placed its order with South Korea's Hyundai shipyard for the first of four of these vessels in September 2004, they were the largest LNG carriers ordered to date. If options are converted into orders, the total cost of the eight ships for BP will be in the region of \$1.5bn, or \$187.5mn each.

A quantum leap forward

The size of the BP ships was, however, eclipsed by the Qatargas II vessels, which will each have a capacity of either 209,000 cm or 216,000 cm and cost around \$230mn. These represent a new generation of LNG vessel, with each of the so-called 'Q-Flex'* ships being provided with an automated LNG reliquefaction plant to return 'boil-off' gas to the cargo tanks, and a pair of 'camshaftless' slow-speed diesel engines for propulsion.

These highly-efficient diesel engines will use inexpensive heavy-oil as fuel. The fuel cost saving could be as much as \$5mn/y, according to Hamworthy, who is supplying the LNG reliquefaction plant. However, further economic benefits will arise because these ships will deliver a greater proportion of their cargo to their destination, since, in addition to returning 'boil-off' to the cargo, the quantity of 'heel' retained onboard for an unladen voyage will be reduced.

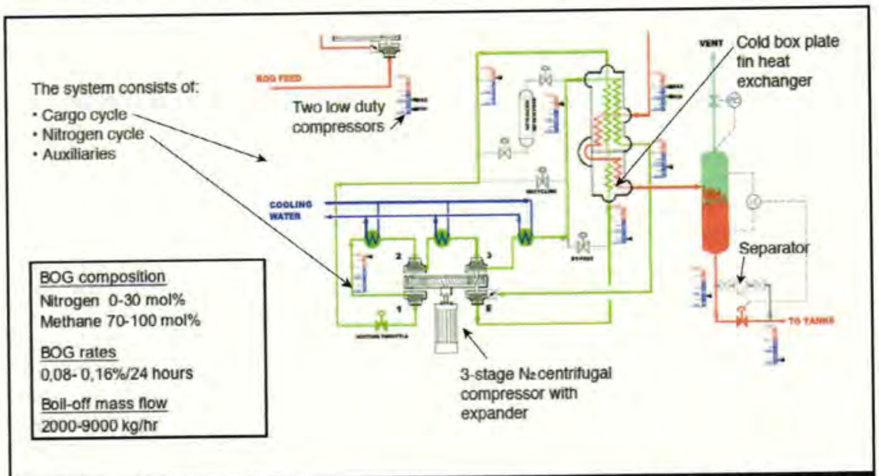
The purpose of this 'heel' is to cool tanks to cryogenic temperature during the unladen voyage, in preparation for loading of the next cargo. The quantity retained onboard represents around 2% of total cargo on present day ships, but is likely to be less for the Q-Flex vessels, perhaps as little as 30–100 tonnes, or the minimum pumpable quantity, because the 'heel' will be recycled.

Slow-speed diesel propulsion

Two reversible, electronically-controlled, slow-speed diesels will be used for propulsion of the Q-Flex ships, with each engine coupled to its propeller via a clutch. This arrangement will allow one engine to be taken out of service, whilst the other continues to provide propulsion. Four diesel generator sets will also be fitted on each vessel to supply electric power.

Photo: MAN B&W

The first ME-C electronic-controlled engine produced to MAN B&W designs – two of these will be used to propel each of the Q-Flex vessels



LNG reliquefaction process *Courtesy of Hamworthy*

The slow-speed engines are massive machines, each occupying a space of around 20 metres long, 10 metres wide, by 12 metres high, with gantry cranes used for lifting components during maintenance. The engine-room layout will present a challenge, since the engines need to be located in the stern of the ship, away from the cargo, where space is limited due to converging hull lines. The design will be further complicated because the engines need to be carefully aligned with their propellers.

This design challenge will be somewhat mitigated by the huge size of the Q-Flex ships, each vessel measuring 315 metres long, 50 metres wide and 27 metres deep, with a service speed of 19.5 knots. The dual skeg design, to support two propellers, is likely add around \$5mn to the hull cost, according to some estimates. But this may be offset by the lower cost of diesels in comparison to steam plant.

MAN B&W is to supply the 6S70ME-C engines for propulsion of each ship, together with the four diesel generator sets. The ME-C is a new variant of engine that does not have camshafts. Instead, the fuel injection, exhaust valves and starting functions are controlled by electro-hydraulic systems. This is a relatively new innovation in marine engineering, with the first ME-C variant being supplied in 2003.

The use of electronic engine control offers improved fuel-efficiency and lower emissions over the entire speed range, because the fuel injection profile can be adjusted to suit operating conditions while the engine is running. This greatly simplifies the task of setting up injectors for optimum performance at high and low speed, since the operation of traditional 'jerk-type' injectors depends on the physical design of a cam, and other mechanical adjustments.

The six-cylinder, two-stroke diesel engines have a 700 mm bore, and 2,800 mm stroke, providing power output of up to 18,660 kW at 91 revs per minute. The electronic engine control has also simplified the mechanical design of these reversible engines by eliminating the cumbersome mechanics that are normally needed to transfer cam followers from the forward and reverse cams, when the engine direction is changed.

Onboard LNG reliquefaction

Hamworthy secured an order valued at £48mn for the supply of the reliquefaction plants for the first eight Q-Flex vessels, and has agreed options for a further 11 ship sets of equipment, with a potential value of £66mn.

The MOSS-RS reliquefaction plant design chosen for the Q-Flex ships differs from conventional small-scale plants typically used for onshore peak shaving, in that only partial liquefaction takes place. In this system, non-condensable gases, such as nitrogen, are separated from the fluid stream, at its cryogenic temperature of –160°C, and released into the atmosphere through a vent or flare. This approach results in a compact design with relatively low power requirements.

Confidence in the technology was boosted by trials of a 60 t/d onshore plant supplied by Hamworthy to Gasnor, in Norway, in 2003. This plant delivers LNG to industrial users and ships, such as the *Viking Energy*, the first offshore supply vessel equipped with LNG-burning diesel propulsion.

It was necessary to automate the reliquefaction plant for the Q-Flex ships to cater for variable throughput of 'boil-off' gas from the cargo tanks. It was also necessary to incorporate a degree of redundancy to ensure the reliable disposal of the 'boil-off' gas under all conditions. The cargo tank pressure on the Q-Flex vessels will be regulated by adjusting the capacity of a two-stage 'boil-off' gas compressor driven by a 460 kW motor.

The compressed 'boil-off' gas will be fed into a plate-fin cryogenic heat exchanger, fitted within a perlite-insulated 'cold box' measuring 4.7 metres by 3 metres by 5.9 metres. On leaving the heat exchanger, the chilled fluids will pass to the separator, with non-condensable gas passing to a thermal oxidiser, and liquid LNG returning to the cargo tank.

The heat exchanger will be cooled by nitrogen refrigerant in a closed-circuit 'Brayton' cycle. This cycle involves three stages of compression, refrigerant cooling and turbo expansion. The compression, and turbo expansion, will take place within a single compact unit driven by a 5.4-MW electric motor. Redundancy will be provided by installing two sets of 100% capacity rotating machines. Gas processing equipment will be located within a cargo machinery room, with separation of hazardous and non-hazardous areas by a bulkhead.

The cooling capacity of the refrigeration system will be regulated by controlling the amount of nitrogen within the loop, with valves to regulate the flow into and out of a storage reservoir. The throughput of the system will thereby be regulated through a range of 0%–100%, with duplication of all the rotating machinery to ensure reliability.

Qatargas II project

The $12bn Qatargas II project will supply 15.6mn t/y of LNG, much of which will go to Milford Haven in south-west Wales. It was described as the world's largest integrated LNG project by partners Qatar Petroleum and ExxonMobil when they unveiled details in December 2004. Total has since joined as a third member of the consortium. The scheme's success will depend on the economy of scale, with each element of the supply chain being significantly larger than preceding projects.

The project partners placed 25-year time charters for eight LNG transport ships of 209,000–216,000 cm capacity with two consortiums. The first consortium consists of ProNav, Commerzbank and Qatar Gas Transport Company; the second consists of Overseas Shipholding, Group-Anglo Eastern and Qatar Gas Transport Company.

Four 209,000-cm vessels are to be built for the first consortium at Daewoo Shipbuilding and Marine Engineering (DSME) of South Korea. Samsung will build two 216,000-cm vessels and HHI two more for the second consortium. When HHI won its orders for the first two 216,000-cm capacity vessels in September 2004, their value was quoted at $230mn each.

**'Q-Flex' is short for 'Qatar-Flexible'. While these are 40% larger than previous LNG carriers, they have a sufficiently shallow draft to allow them to use most existing terminals. However, Qatar is due to purchase even larger 'Q-Max' ships in the near future, with capacity of 260,000 cm of LNG. These are the largest that can be loaded at Ras Laffan port in Qatar, but could be too large for some existing import terminals.*

...continued from p13

the industry. If more than one standard is produced it will cause confusion, even if they say the same thing in different ways. The goal should be to find a way to identify precisely what training is needed by personnel with complementary qualifications, after which a modularised training process can be established. In this way training can be standardised and costs can be kept down.

For example, Gillet said, a master with LPG experience would only need training in LNG equipment and procedures, cargo conditioning, and the use of boil-off gas as fuel.

Model maker

Meanwhile, DML has taken practical steps to help train deck officers and, in cooperation with the Ilawa training school in Poland, has developed a ride-on model LNG carrier. The aim is to familiarise deck officers with the particular handling characteristics of LNG carriers, which are usually large, fast and sit high in the water, even when fully laden, thus being susceptible to cross-winds.

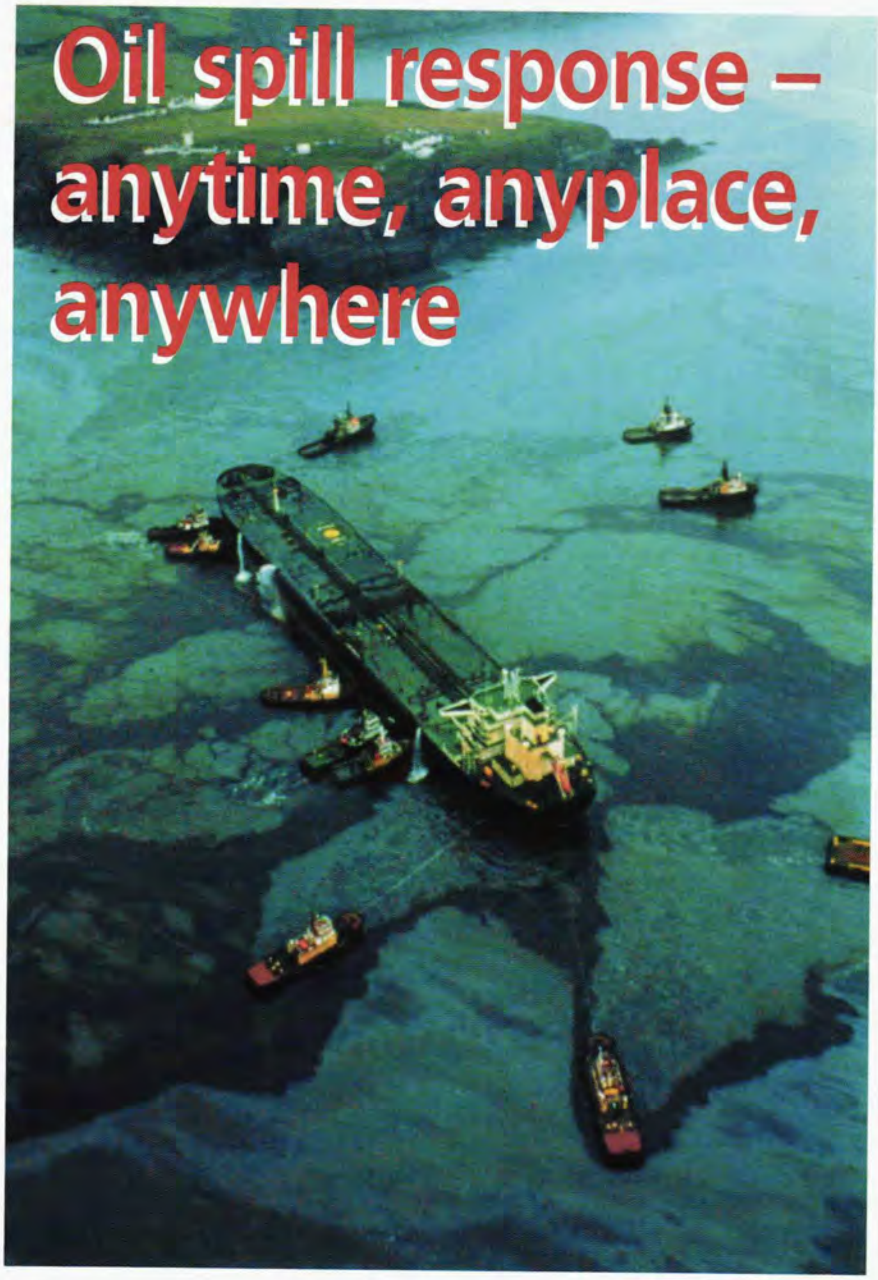
The model, dubbed *Dorchester Lady*, is 11.5 metres long and based on the typical membrane ships currently being built in Korea, although it can be altered to mimic the Moss-type design. There are significant differences in handling between the two designs, as Moss ships have spherical tanks offering considerable windage. The model can also be adapted to simulate single- or twin-screw diesel propulsion as well as the standard steam plant layout.

In addition to the model itself, DML has supplied Ilawa with full details of the layout of the ports that the LNG tankers under its management commonly visit, as well as information about the tugs that assist the tankers in berthing. The use of the model forms part of the LNG-specific training recommended by DML.

Pressly remarked that gas ship and cargo handling courses offered by maritime colleges tend to concentrate more on LPG tankers, since these are more numerous, and that such training is not appropriate for LNG personnel. DML has found it necessary to establish its own training courses to allow it to produce a coherent team for each LNG tanker it manages.

'Provided the industry faces the current fleet expansion in an open-minded way and recognises the value of a structured, coherent and sustainable training,' Pressly concluded, 'we are confident that we can continue to provide the exceptional levels of reliability and safety achieved by LNG shipping since its earliest days.'

Oil spill response – anytime, anyplace, anywhere



Sea Empress spill, Wales, 1996

Oil Spill Response Ltd's (OSRL) Senior Spill Response Specialist, Abigail Findlay, *explains how the OSRL/EARL Alliance is adapting to the changing needs of the global oil industry.*

The oil industry's strategy for spill response has been well defined for many years. It is referred to as the 'Tiered Response Concept' – the main philosophy of which is to match response resources to the actual risk posed by operations in any area. This avoids excessive stockpiles and unnecessary duplications of response/clean-up equipment, while increasing the speed and efficiency with which a response can be executed. The mechanics of the concept are often illustrated as laid out in **Figure 1**.

At the basic, or 'Tier 1', level every operator should have resources on site to deal with operational spills. At the next level co-operatives should be formed between operators within a region to allow access to each other's equipment. This is the 'Tier 2' response. When the regional Tier 2 is exceeded international industry stockpiles will be required. These are referred to as 'Tier 3' stockpiles. Oil Spill Response Limited (OSRL) in the UK and East Asia Response Limited (EARL) in Singapore are two key Tier 3 bases.

Working in partnership

OSRL is the world's largest international oil spill response company and has been the oil industry's global response facility since 1985. In partnership with EARL – the largest such organisation in the Asia-Pacific region – they formed the OSRL/EARL Alliance and now jointly provide resources for effective and efficient oil spill response and preparedness on a global basis.

Both organisations are not-for-profit operations, wholly owned by 29 of the most responsible and environmentally committed oil companies. Each member company, or participant, contributes an annual fee and receives guaranteed response worldwide, 24 hours a day,

UKCS aircraft in action

throughout the year. The OSRL/EARL Alliance resources are combined for the benefit of all members, ensuring that services can be provided from either OSRL or EARL, or a combination of the two. The formation of the OSRL/EARL Alliance was driven by the changing needs of the oil industry. As many of the member companies have been forced to outsource what were formerly in-house functions, the Alliance is relied upon to provide a holistic, robust service.

The OSRL/EARL Alliance has become more prominent in recent years due to the increased public and media awareness of environmental issues – even though the incidence of oil spills has continued to fall – as illustrated in **Figure 2**, which highlights the steady decrease in ship source pollution incidents.

OSRL Hercules spraying dispersant

Be prepared

Such issues have thus increased in significance on government agendas, leading to increasing pressure on the oil industry to perform to ever higher environmental and quality standards. To tackle this issue, the Alliance has grown its services to ensure that preparedness issues are fully met prior to an incident. This reduces the chance of spills and, in the actual event of a spill, allows more efficient and rapid response.

Services now provided by the Alliance include paper, electronic and interactive contingency planning; training courses accredited to International Maritime Organisation (IMO) and UK Nautical Institute standards; in-depth audits of equipment and plans; and both tabletop and physical exercising of plans at regular intervals.

As global communications improve, the expectation for faster and more efficient spill response has increased. The Alliance has tackled this in a number of ways. Both OSRL and EARL have their own dedicated Hercules L382G cargo aircraft capable of carrying around 20 tonnes of spill response equipment. The EARL Hercules was also used by oil companies during the recent tsunami disaster to get relief to the devastated Asian countries.

Over long distances it is more effective to use jet aircraft, so the Alliance has a dedicated broker with a confirmed line of credit who maintains a 24/7 overview on aircraft available on the charter market. The confirmed line of credit allows the broker instant access to any suitable aircraft. More recently, an agreement has been made with DHL to access its standby fleet, giving a permanent reserve aircraft for use by the Alliance. This range of options allows rapid response no matter what the circumstances.

Improving global response

Improving global response using existing industry resources has been one of the main objectives of both OSRL and EARL for many years. The first major step towards increasing service options globally was, as stated earlier, the formation of the OSRL/EARL Alliance. Following on from this, memoranda of understanding (MoU) were signed with other response organisations in countries across the globe. These MoUs promote co-operation between organisations in the time of a spill.

In 2004, the Alliance and the Marine Spill Response Corporation took their MoU a step further, to form the Global Response Network (GRN). The GRN allows industry-funded, not-for-profit organisations to exchange personnel and equipment at no cost during spills and 'peace time'. It also promotes the formation of best practice and industry standards regarding spill response, health and safety, planning, training and other related issues through cross-fertilisation of ideas. The Clean, Caribbean & Americas Co-operative,

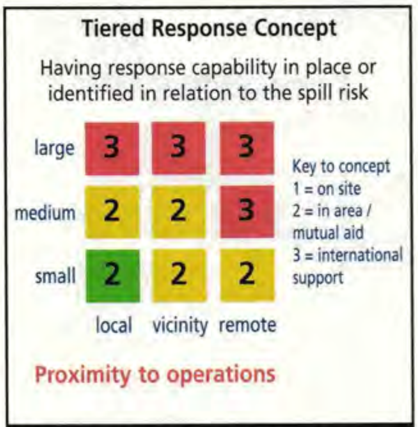


Figure 1: The oil industry's tiered Response Concept

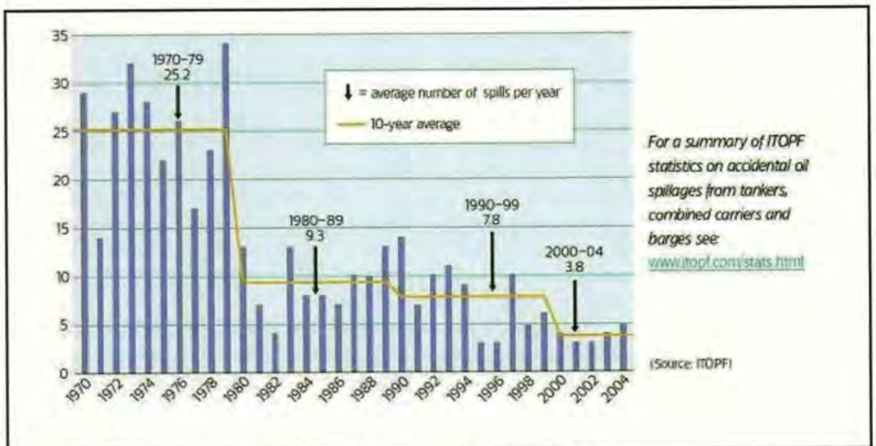


Figure 2: Trend in major spills of petroleum products from shipping

EARL Hercules being loaded with aid for the December 2004 tsunami victims

Australian Marine Oil Spill Centre and Alaska Clean Seas are the latest organisations to join the GRN, further enforcing the global links and improving response effectiveness to a new level.

Oil companies noted that in some areas there was a need for more localised, immediate response solutions. To alleviate this, the Alliance has provided specific services to the UK Continental Shelf (UKCS) and West & Central Africa (WACAF) regions in the form of affordable Tier 2 aerial dispersant services. These comprise a surveillance aircraft with onboard remote sensing equipment to monitor spills, together with a second aircraft modified to carry approximately one to two tonnes of dispersant. These solutions have proved very successful in dealing with small spills quickly and effectively.

The Tier 2 aircraft can also act as the intermediate response to a larger spill until the Tier 3 aerial dispersant service is in place. The Tier 3 service comprises an Alliance Hercules loaded with the Aerial Dispersant Delivery System (ADDS) pack or the new modular dispersant spraying tank system (NIMBUS™), which are amongst the most effective methods of dealing with large offshore slicks.

Global initiative

As well as resolving and supplying solutions to response issues the oil industry looks to the Alliance to engender global cooperation between industry and governments. This is achieved through an in-depth involvement with international governments and industry bodies. The International Petroleum Industry Environmental Conservation Association (IPIECA) and the International Maritime Organisation (IMO) set up the 'Global Initiative' (GI) programme to promote such cooperation.

The GI programme encourages and, where possible, assists receptive countries to ratify the relevant international oil spill conventions, and encourages effective and sustainable national and regional oil spill contingency planning.

EARL training course in Taiwan

In order to introduce the key principles of effective contingency planning to a wider government and industry audience, IPIECA and IMO have recognised the need to engage this debate with policy makers as well as those responsible for implementing national response systems. The Alliance is used to develop the GI programme and works within IPIECA to coordinate and deliver training courses internationally.

No matter how robust the resources the Alliance puts in place for an oil spill, truly effective preparedness and response can only be attained through co-operation and full understanding from all stakeholders – be they oil companies, governments, response organisations or local communities.

Case study – oil well blowout in Tbilisi, Georgia

On 13 September 2004 the OSRL/EARL Alliance was called out to Tbilisi in Georgia, in response to a significant inland oil well blowout, writes *Emily Rowe*, OSRL Spill Response Specialist. As the first inland oil well blowout that the Alliance had responded to, the challenges of the location, close proximity to a residential area, contamination caused and the environmental impact were significant and unique. The Alliance immediately mobilised a duty manager and spill response specialist.

The wellhead was positioned on a plateau surrounded by deciduous woodland, so a detailed environmental survey was required. A strong headwind caused approximately 5,000 tonnes of oil and water to be dispersed across an area covering some 1 sq km of woodland and 2 km into a nearby village. The environmental report detailed the impact that the spill would have on the locality, wildlife and the potential public health issues the local village may subsequently encounter – which included the contamination of crops and water supplies.

The response strategy required mobilisation of both environmental and technical response specialists to implement the plan and to effectively deal with the conditions facing the clean-up team. The main strategies for clean-up were firstly to prevent the oil running down the hillside to a nearby village and, second, to prevent it travelling along any water courses. This was achieved by digging ditches across the hillside to catch the oil, which could then be recovered with conventional vacuum skimmers. Flushing techniques were also used to enhance the movement of the oil into the ditches. In total, over 9 tonnes of specialist equipment was airfreighted from OSRL's Southampton base to Georgia.

After several weeks, the Alliance demobilised and local responders continued to implement the remaining elements of the response strategy. Alliance staff then revisited the site in January 2005 to monitor the recovery.

As can be seen from the before and after pictures, the clean up techniques had been successful.

Before – the impact of the well blow-out in Georgia

After – Wellhead area recovering successfully four months later

Making a difference

Lena Blomqvist, Vice President, Environment, Wallenius Wilhelmsen, outlines the work that the company is doing to minimise the impact of its shipping operations on the atmosphere and the sea, in a bid to help alleviate the problem of global warming.

Scientists at the Scripps Institution of Oceanography, University of California, San Diego – one of the world's largest and most important centres for global science research – reported in February 2005 the first unequivocal link between man-made greenhouse gases and a dramatic warming of the Earth's oceans. Dr Tim Barnett, a research marine physicist in the Climate Research Division at Scripps, said that he was 'stunned' by the results, because the research provided: 'The most compelling evidence yet that global warming is happening right now.'

An earlier study by Barnett and his colleagues concluded that global warming will likely alter western snow-pack resources and the region's hydrological cycle – posing a water crisis in the western US within the next 20 years.

Because the global climate is largely driven by the heat locked up in the oceans, a rise in sea temperatures could have devastating effects for many parts of the world.

Now, while it would be nonsensical to suggest that ships have a big impact on acid rain, shipping is nonetheless part of the environmental problem. As a global leader in vehicle and RoRo (roll-on, roll-off) transportation and vehicle logistics – operating some 60 ships – we, at Wallenius Wilhelmsen (together with our joint owners Wallenius Lines of Sweden and Wilh. Wilhelmsen of Norway) believe we can make a real difference to the environment by cutting harmful emissions into the atmosphere and cutting discharges into the sea.

As part of this drive, in January 2005, Wallenius Wilhelmsen signed two key contracts for the supply of low-sulphur bunker fuel – with a sulphur content of just 1% – that will help the company meet its ambitious environmental target for 2005. Our yearly bunker fuel requirement in 2005 is around 800,000 tonnes.

A 3 year contract, which runs until 31 December 2007, was secured with Shell Marine Products for the supply of between 200,000 t/y and 300,000 t/y of low-sulphur (1% sulphur content) bunker fuel to Gothenburg and Bremerhaven. The second contract was signed with ExxonMobil, covering the supply of between 100,000 t/y and 115,000 t/y of bunker fuel with a similarly low sulphur-content to Southampton.

These contracts followed a number of groundbreaking supply agreements secured in 2004, covering the purchase of bunker fuel with a sulphur content of between 1% and 1.5% – well below that required by current legislation to help stem harmful exhaust emissions into the atmosphere. International standards currently require that, from 2006, ships will need to meet a 1.5% sulphur standard in the Baltic. Legislation will also require that in 2007 a similar figure needs to be reached for the North Sea, Irish Sea and the English Channel, while the remainder of the world will need to adhere to a 4.5% target.

E/S Orcelle – a radical vision of the future of ocean transport

Wallenius Wilhelmsen has brought together a multidisciplinary team of naval architects, environmental experts and industrial designers to work on the *E/S Orcelle* concept ship model.

The *E/S Orcelle* is designed to use renewable energy sources, including the sun, wind and waves, as well as fuel cell technology, to meet all propulsion and onboard power requirements. It has a 'zero' emissions capability and carries no ballast water.

Solar energy is harnessed through photovoltaic panels in the vessel's three sails, which also help propel the vessel using wind power. These sails are manufactured using special lightweight composite materials.

Wave power is utilised through a series of 12 fins, which will be able to transform wave energy into hydrogen, electricity or mechanical energy. The fins double as propulsion units, driven either by wave energy or other renewable energy sources onboard, while the vessel's propulsive power will also be provided by two variable-speed electric propulsion systems known as 'pods'.

Around half the energy on the *E/S Orcelle* will be produced by fuel cells, a rapidly developing new technology. These cells will combine hydrogen and oxygen to generate the electricity that will be used in the pod propulsion systems and the fins, while also producing electricity for other uses onboard. The only by-products from this process are water vapour and heat.

Cargo carrying capacity has also been optimised, so that this visionary design could carry approximately 10,000 cars – around 50% more than today's car carriers – while having a similar weight in tonnage terms. This increased level of efficiency has been achieved through the use of lightweight materials, including aluminium and thermoplastic composites, and also by eliminating the need for ballast water tanks.

According to the International Maritime Organisation (IMO), ballast water is one of the main environmental threats to the world's oceans. Wallenius Wilhelmsen proposes to completely eliminate the need to take on, and release, ballast water, by using an innovative pentamaran hull – featuring a long and slender main hull and four supporting sponsons – as well as by utilising a pod-type electric propulsion system that dispenses with the traditional stern propeller and rudder arrangement. ●

Meeting the challenge

However, while substantial progress has been made in this area, we at Wallenius Wilhelmsen are still concerned at the continued high sulphur content of marine fuel in general and the lack of availability of low-sulphur bunker fuel outside Europe. The real challenge for the petroleum industry is to be able to provide sufficient quantities to meet demand.

It is estimated that in Europe alone bunker fuel refining will need to be increased from 1mn to 10mn t/y to meet the expected demand from shipping companies following the introduction of tougher legislation. Yet the oil industry has raised doubts about whether it can meet this demand, even in Europe. It has already given indications that there will be price premiums to increase production of lower sulphur fuels on top of the heavy premiums the shipping community is already paying for such bunkers.

In addition, concerns have been voiced about the quality of the fuel supplied. For example, we have found that one of the ways that petroleum companies used to meet our 1.5% sulphur level requirement was to blend various qualities of fuel. However, a blended product might be unstable and cause increased wear on, and even stoppage of, vessel engines.

The oil industry says that modern engines are built to burn heavy fuel oil (HFO) that is of 'lower' quality by using filtering and heating techniques. This might be true – however, like other shipping lines, Wallenius Wilhelmsen operates older, well-maintained tonnage equipped with older types of engine that cannot easily use a lower standard of fuel.

We intend to use our tonnage as long as it is economically and environmentally feasible – up to 25–30 years – so this is an issue that oil companies need to resolve.

Emissions control

Wallenius Wilhelmsen is also busy implementing a number of measures to control emissions into the atmosphere. We have installed slide fuel valves on board 14 of our ships. Four further ships will follow by the end of this year. As a result, there has been a reduction in nitrous oxide (NO_x) emissions of between 20% and 30%, coupled with a reduction in the level of particulate matter (PM) in exhaust gases.

We are also set to trial a combustion air saturation system on board a 1999-built vessel to reduce NO_x emissions even further.

The industry favours the installation of desulphurisation plants onboard ships rather than at the refinery stage as a way of combating harmful exhaust emissions. While we do not object to the desulphurisation methods proposed by the oil companies, surely it is far more practical to desulphurise fuel on land rather than transferring the problem to ships, where space is at a premium for cargoes? The size of the desulphurisation equipment not only reduces cargo space, its weight also demands extra fuel – and, in turn, the emissions per unit of cargo we carry will go up.

Tackling the issue head on

There are several parties advocating emissions trading as one possible means of meeting sulphur and other emissions targets. However, this does not really tackle the environmental goal of reducing global emissions themselves – which is what we, at Wallenius Wilhelmsen, are striving to do.

Indeed, the company's stance is supported by many like-minded shipping companies and our major automotive manufacturer customers, who have big environmental programmes for their own products. Our customers welcome the fact that Wallenius Wilhelmsen is environmentally certified by ISO, and they are keen to continue to transport their cargoes on environmentally-friendly transport.

Environmental agenda

The use of low-sulphur fuel is not the only environmental topic on Wallenius Wilhelmsen's agenda for reducing the impact of its vessels on the world's ecosystem.

Other measures already undertaken include altering main engine fuel combustion to minimise emissions; using tin-free bottom paints on hulls; innovative methods of treating ballast water; use of ship's double hulls; changing cooling agents used in refrigeration plant; implementation of biodegradable oil in the stern tubes; finding more environmentally-friendly systems to put out fires; bilge water treatments achieving content of 5 ppm; and using biocide-free antifoulants.

Regarding emissions into the sea, ballast water is one area where we believe we can help provide some positive input in helping to improve the marine environment.

It is estimated that between 3bn and 5bn tonnes of ballast water is transported annually by ships carrying foreign flora and fauna. The expulsion of these vessels' ballast water can really threaten the native marine habitats as ships pick-up seawater in one ocean and deposit it in another.

One of our owners, Wallenius Lines, has been trialling a ballast water treatment system* through its subsidiary Benrad AB, in partnership with Alfa Laval of Sweden, which will be ready in 2006. It consists of an advanced oxidation technology (AOT) process that eliminates micro-organisms and bacteria, while reducing other organic materials, without adding chemical substances or generating residual by-product.

While Wallenius Wilhelmsen already makes considerable effort to be 'greener' with regard to emissions into the air and sea, we wanted to help preserve and promote conservation of marine life on the high seas in a more substantive way. So, in September 2004, we signed a ground-breaking, three-year agreement with the WWF, which aims to strengthen the work of WWF's Global Marine Programme on conservation of the high seas (areas of the open ocean outside a nation's exclusive economic zone) and WWF-Norway's Endangered Seas Programme.

Looking to the future

Wallenius Wilhelmsen is also looking to a future world where fossil fuels most probably will not be in plentiful supply. Like the oil industry, we are looking at alternative technologies and different sources of power to drive our ships in the future – from solar energy to wave power.

In a bold effort to find a truly environmentally friendly means of ocean transportation we have built a concept model called *E/S Orcelle*** – our zero emissions car carrier and RoRo ship of the future. Powered by the sun, wind and waves, this futuristic ship has no conventional engines, uses no fossil fuels, releases no harmful emissions into the atmosphere or pollution into the sea, and carries no ballast water. The ship's groundbreaking design incorporates a cargo deck area equivalent to 14 football fields. It has the capacity to carry up 10,000 cars in emission-free conditions across the world's oceans. (See separate box piece.)

While we have no immediate plans to build a prototype of the *E/S Orcelle*, we hope our model will stimulate others to develop the technologies embodied within the concept design, so that they do become practical options for newbuildings within the next 20 years.

Wallenius Wilhelmsen is here for the long term. We want to be perceived as one of the most environmental friendly companies on the planet. To achieve this we need to continue to find innovative solutions to minimise our impact on the environment and we look to the oil industry to proactively help us in our environmental endeavours. Pursuing such goals is good for business and good for the planet. ●

**Benrad and Alfa Laval won the Protection of the Marine and Atmospheric Environment category at the Seatrade 2005 Awards for this innovative technology, while Wallenius Wilhelmsen was granted a special commendation for its environmental stance.*

***E/S stands for Environmentally Sound Ship. The ship is named after the Irrawaddy dolphin, which is also known (in French) as the Orcelle dolphin. WWF, the global conservation organisation, includes the Orcelle dolphin among the world's critically endangered species.*

Clean Cargo Working Group

The Clean Cargo Working Group is a global consortium of multinational manufacturers, shippers and carriers, which came together to promote cleaner and more environmentally sustainable transportation.

Wallenius Wilhelmsen is the first non-container shipping carrier to join the group, which is currently working on developing an environmental performance system (EPS) to measure exhaust emissions. This should go a long way to resolving the issue of how customers can uniformly monitor their carriers' emission levels and environmental profiles effectively. ●

Environmental information

Visit **www.2wglobal.com** to find out more about Wallenius Wilhelmsen's environmental policy and objectives, including a pdf download of the 2004 report *Environmental Care Shaping our Business*.

For more information about the WWF, visit **www.panda.org/marine**

Gas in the pipeline

Jay Chaudhuri, *Project Manager, Medgaz, and* Ian Nash, *Project Manager, Intec Engineering (UK), provide an overview of the Medgaz pipeline project that will transport 16bn cm/y of gas from Algeria to Spain from 2008, providing security of supply for the Iberian Peninsula.*

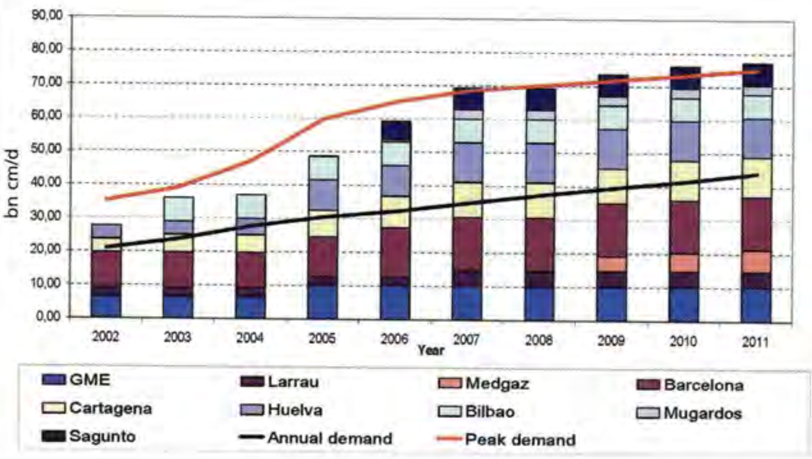


Figure 1: Spanish gas system capacity *Source: CNE, 2004*

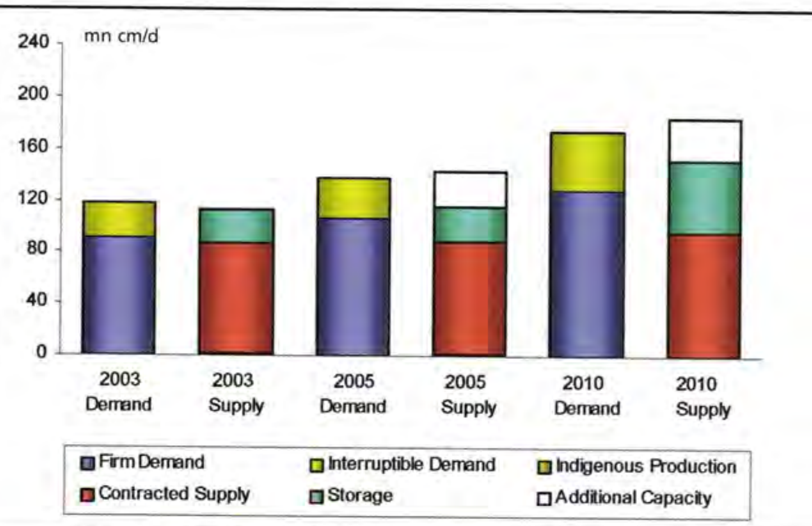


Figure 2: Spanish peak-day gas supply/demand *Source: Wood Mackenzie, 2003*

High pressure pipelines have proved to be the safest, cheapest way of transporting gas to the market for short to medium distances up to 2,500 km, making the proposed ultra-deepwater Medgaz pipelines an economic solution for gas delivery to the Iberian Peninsula. Linking Algeria and Spain across the Mediterranean Sea for an offshore distance of 200 km, the project is designed to transport up to 16bn cm/y of gas into the Iberian and European energy markets. When commissioned in 2008, Medgaz will be well-placed to meet the demand for natural gas in the Iberian market, which is growing at annual rates of 17%. Phase 1 of the project will transport between 6bn and 7bn cm/y of gas.

In June 2003, Intec Engineering (UK) was awarded the front-end engineering design (FEED) phase of the Medgaz project. The offshore portion of the pipeline route crosses the Alboran Sea in water depths greater than 2,150 metres and the design of the large-diameter pipeline includes many project-specific challenges. Relevant issues include construction and maintenance in ultra-deepwater, geo-hazards and seismic risks associated with the continental shelf margins.

Iberian gas requirements

Iberia's fast-growing energy market poses a number of challenges to the existing infrastructure. Spanish gas consumption alone has grown from 21.4bn cm in 2002 to 28.3bn cm in 2004, and it is estimated that annual demand will exceed 44bn cm in 2011 (see **Figure 1**).

Manufacturing growth and the need to switch to friendly fuels, as dictated by the Kyoto Protocol, is increasing gas demand by an estimated compound rate of 17%/y. In contrast, the available system capacity is barely managing to keep pace with the growth in demand, resulting in a gas supply shortfall in peak winter periods. To meet this shortfall, a number of gas infrastructure projects are currently under way. However, it is anticipated that peak capacity shortages, which are currently being experienced in Spain, will stretch to at least 2010 (see **Figure 2**). It is feared that delays in increasing the gas and power infrastructure capacity could harm the fast-growing economy of the region and the development of the Iberian energy market in the short- to medium-term.

The long-run marginal cost (LRMC) (excluding producing country royalty) for potential gas supply to Spain has been studied extensively by independent energy consultants OME and Wood Mackenzie. These studies indicate clearly that the proposed Medgaz gas project will be the lowest-cost supply option for Spain (see **Figure 3**), resulting in clear economic benefits for the whole of the Iberian Peninsula.

Project overview

The Medgaz project was initiated in 2001 by CEPSA of Spain and Algeria's state-owned company Sonatrach. Since then, the partnership has grown to seven members, as shown in **Figure 4**.

The gas supply system in its entirety consists of 500 km (48-inch diameter) of onshore pipeline in Algeria that will be owned and constructed by Sonatrach, and which connects to the offshore Medgaz pipeline at Sidi Djelloul in Algeria, where the Beni Saf compressor station (BSCS) is located. The Medgaz pipeline system consists of two 24-inch diameter submarine pipelines, each 200-km long, which cross the Mediterranean (Alboran Sea) from Sidi Djelloul, Algeria, to Almeria, Spain. The maximum water depth experienced along the route is 2,155 metres. At the offshore pipeline receiving terminal in Almeria (OPRT), connection is made to the 48-inch diameter Spanish onshore pipeline, which will be owned and constructed by others, to connect into the Spanish grid system.

The Medgaz project covers the BSCS, ORPT, subsea pipeline and two short onshore sections of high-pressure pipeline that connect the submarine pipeline to the compression and receiving facilities respectively. A schematic of the subsea pipeline crossing of the Mediterranean is given in **Figure 5.**

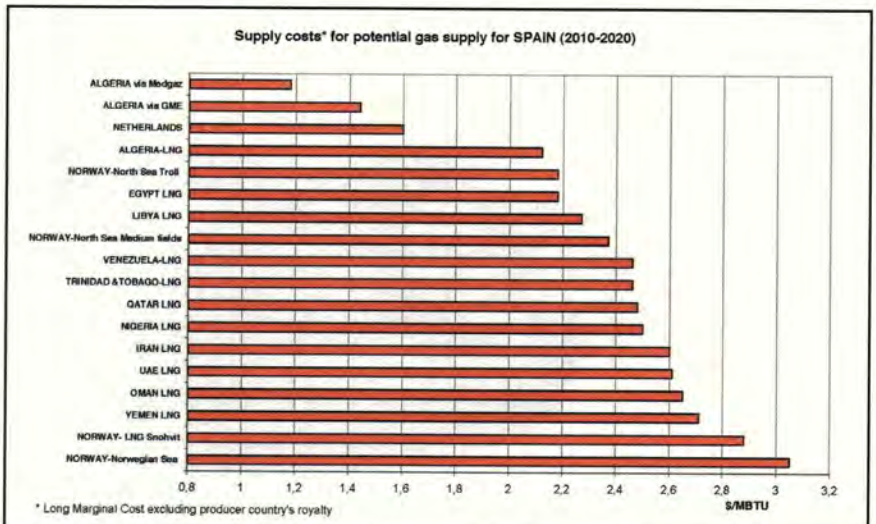


Figure 3: Long-run marginal cost (LRMC) for gas supply to Spain, 2010–2020

Source: OME

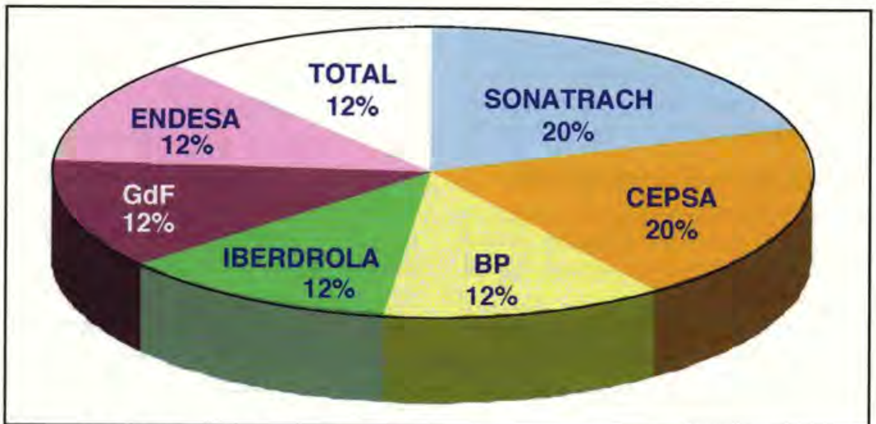


Figure 4: Medgaz partnership structure

Technical data and design constraints

The design life of the Medgaz pipeline is 50 years, with a total system throughput requirement of 16bn cm/y at 220 bar g pressure. This throughput, however, is only required in year 15, with a proposed build up from between 6bn and 8bn cm/y over the first five years. Based on this stepped increase in throughput, a phased approach has been adopted for the two pipelines. Phase 1 will be the construction of the easterly of the two pipelines, plus the short onshore and shore approach sections of the westerly pipeline; the civil works for the compressor station at Beni Saf and receiving terminal near Almeria in Spain; the compressors and associated facilities for 8bn cm/y capacity with three compressors in service (2 LP and 1HP). Phase 2 will see the construction of the second submarine pipeline (West Pipeline) connecting the pre-installed shore approach stubs of the Sidi Djelloul and Almeria landfalls, plus the installation of a further two compressors (1LP and 1HP) at the Beni Saf compressor station to raise the throughput to 16bn cm/y. The development throughput is summarised in **Table 1.**

To meet the demanding requirements of the ultra-deep Medgaz pipeline, extensive marine surveys were performed during the 2002–2004 period, commencing in June 2002 with an initial survey performed by C&C Inc to gather information on bathymetry, seabed features and soils, which allowed the selection of a potential pipeline route. Based on the selected initial route for the pipeline, Fugro performed a geotechnical survey in July and August 2003. This survey collected detailed information on the nature of the seabed and soil characteristics along the pipeline route. The survey also investigated hazards identified by the Phase 1 Study by Snamprogetti and CSIC. This was followed in August through October 2003 with near-shore and onshore geophysical and geotechnical surveys by GAS.

The main findings from the geotechnical survey were:

- Slope and deepwater areas are composed of mainly soft or very soft clays – no volcanics or turbidites.
- No evidence in sediment cores of recent soil mass movement.
- No evidence of hydrogen sulphide gas; mud volcanoes or mud flows.

In 2004, two further surveys were performed to complete the detailed under-

Year	1	2	3	4	5	15
Flow (bn cm/y)	6	7	8	8	8	16
No of pipelines	1	1	1	1	1	2

Table 1: Phased development throughput for Medgaz

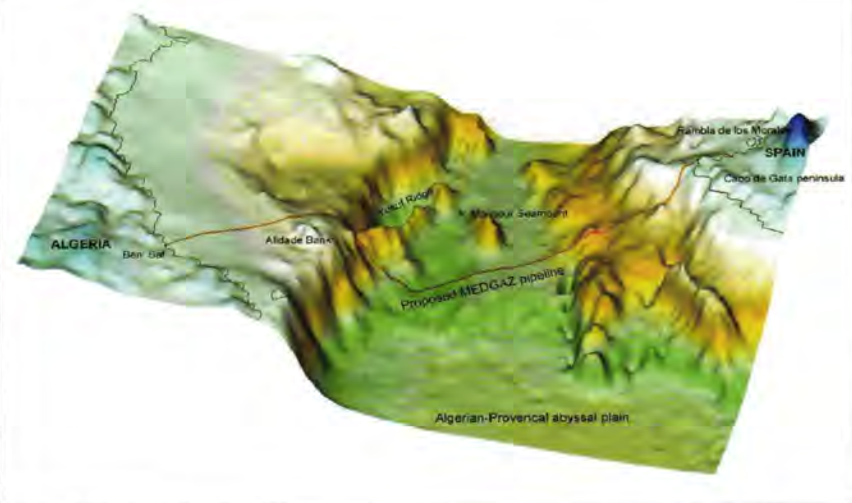


Figure 5: Medgaz pipeline route

standing of the route and its features. These included an ROV/AUV detailed geophysical survey performed by Geoconsult (May–June 2004) and a high resolution multi-channel seismic survey performed by Fugro Survey (June 2004).

Routing and geohazards

The information provided by the survey campaigns permitted selection of the optimum pipeline route to meet the following objectives:

- Minimisation of environmental impact.
- Protection of marine flora/fauna on the offshore and onshore sections on the Algerian and Spanish sides.
- Avoidance of natural obstacles that exist along the route.
- Low geological and geotechnical risks.
- Minimal number of cable crossings.
- Ensuring the feasibility to employ S- and/or, J-lay construction method.
- Minimisation of 'free-span' risks.

The resulting pipeline route from landfall to landfall has a route length 198.3 km and reaches a maximum depth of 2,155 metres approximately midway along the route, with approximately 50% of the pipeline having depth greater than 1,000 metres. In total, the route is described by 19 changes in direction and crosses five live telecommunications cables, at depths greater than 1,800 metres. The proposed route is characterised by a geological fault crossing known as the Yusuf Fault, located on the upper Habibas escarpment and with steep slopes (approximately 14°) on part of the lower Habibas escarpment.

Environmental issues on land

The Medgaz project has also applied proven environmental principles for the design of its terminals. Some of the design features considered to minimise environmental impact include:

- Specification of dry low-emission turbines for compressor drives.
- Selection of BSCS compressor configuration for optimum fuel consumption at projected gas transportation rates.
- Use of air for actuation of BSCS valves.
- Use of flaring (instead of venting) during planned de-pressurisation of either terminal.
- Specification of low NO_x (nitrous oxide) burners for OPRT gas re-heaters.

Project rating for Israel's landmark gas project

Photo: Zion Oil & Gas

The Yam Tethys project marks an important milestone in Israel's march towards energy self-sufficiency, writes Jan Plantagie, *Director, Project Finance, Standard & Poor's.*

Israeli project company Delek & Avner–Yam Tethys recently secured a BBB– rating for its $275mn notes issue. The investment grade bond rating marks a milestone in the evolution of Israeli project finance, but also for oil and gas project finance globally.

Yam Tethys – a joint venture between the Delek Group sponsors (Delek Drilling, Delek Investment & Properties and Avner Oil Exploration) and Nobel Mediterranean – owns and operates a gas production facility off the coast of Israel. Natural gas is drawn from the Mari-B reservoir and is sold through a 10-year take-or-pay gas sale and purchase agreement (GSPA) to state-owned Israel Electric Corporation (IEC). Total contract quantity for the lifetime of the GSPA is about 18bn cm.

The bond issue monetised the Delek sponsors' 53% share of revenues from the GSPA with IEC – using the proceeds to refinance debt facilities put in place to fund the project's original development, as well as finance future capital expenditure, replenish working capital needs and fund a distribution to shareholders. The structure includes covenants typical of project finance deals – including restrictions on incurring additional debt – as well as a requirement that the Delek sponsors maintain a proven gas reserve to the remaining total GSPA contract quantity of at least 130%, or 50bn cm. Furthermore, with a minimum sale volume of 1.4bn cm/y and a gas-price hedge agreement secured by the Delek sponsors for their share of the IEC deal, price risk has been limited and the contractual structure has been strengthened – all of which has helped the issue secure investment grade credit ratings.

Yam Tethys discovery well

The Mari-B reservoir was discovered in 2000 by Avner Exploration and Delek Drilling. Construction of the Yam Tethys project was completed by the end of 2003 and the facility was commissioned in February 2004. It uses commercially proven technology, and was built to Gulf of Mexico standards, which far exceed the demands of the Mediterranean environment. Crucially, the project enjoys high reliability, with very few problems encountered since operations began – factors that point to stable output and revenue generation. Overall, the project has a robust financial forecast, with a healthy expected average debt service coverage ratio over the 8.5-year debt tenor of 1.61x.

The facility consists of an offshore gas production platform, which services five offshore gas production wells. A 42-km, 30-inch subsea pipeline links the platform to the temporary onshore receiving terminal that is connected to IEC's power station at Ashdod and the IEC coastal pipeline. A permanent receiving terminal will be constructed in 2005–2006 to link the Yam Tethys facility to the then completed national gas transmission network.

Mari-B is an outstanding field, with proven estimates of 25.6bn cm of high-quality gas. Indeed, as Israel's energy security commands strategic importance, Yam Tethys was declared to be a national strategic project as it is the sole supplier of natural gas to Israel. Output will feed a national gas transmission network that is being constructed in line with moves by IEC to harness the price and environmental benefits of gas-based generation. The state-run generator is also converting diesel-fired power stations to burn gas.

Competitive risk

While the next few years will see Yam Tethys hold a strong market position, in the medium term competitive risk will increase, driven by increasing sources of gas supply. For instance, an additional gas pipeline from Egypt is planned for completion in 1Q2007, although the timing of this appears optimistic.

Further competitive risk lies with the intention of the Israeli government to encourage greater competition in the utility sector – a situation that could see IEC take reduced volumes of gas. Indeed, IEC can reduce its level of gas offtake throughout the life of the project, subject to a minimum annual contract quantity of about 1.4bn cm. Were this to happen, the debt-service coverage ratios would suffer, although the project is covered by strong liquidity features, such as business interruption insurance, a six-month debt service reserve and a 'rated amortisation' facility, which allows the borrower to postpone the scheduled principal repayments in the event that IEC's offtake is less than expected.

Sustaining refining margins

As the last round of corporate earnings announcements showed only too clearly, economic conditions for petroleum refiners are highly favourable at the moment. Linus Hakimattar, *Vice President Petroleum Marketing, Aspen Technology, explains how IT solutions can help refiners overcome operational challenges and maintain higher margins – even when conditions are less favourable than they are today.*

While profits are currently high, refiners that wish to sustain high margins in the future still need to overcome some significant operational challenges. The priorities vary according to a refinery's age, technical configuration and complexity, typical feedstocks and product slate, but the main operational issues facing refiners can be summarised under the following headings:

- Safety and reliability.
- Clean fuel requirements.
- Energy costs and emissions targets.
- Changing product mix.

The good news for refiners is that although the challenges they face have been evolving, there is now a more sophisticated range of tools available to help them tackle the different obstacles that they encounter. In particular, new generations of information technology (IT) solutions have been developed that are designed specifically to address the business processes that are unique to the refining industry, and which can be deployed rapidly to maximise today's benefits while ensuring the sustainability of those benefits into the future.

In each of the categories cited above, refiners now have access to IT solutions that can have a significant impact on operational performance. More than that, the latest offerings are no longer individual 'point' applications that solve a single business problem. Increasingly, fully-integrated solutions that link to existing enterprise applications – such as distributed control systems (DCS) and enterprise resource planning (ERP) systems – and which support collaboration between different functional groups, are becoming available. This trend not only results in increased organisational effectiveness and operational reliability, but also in lower overall IT cost-of-ownership.

Safety and reliability

With margins now approaching record highs, refiners are currently most concerned by the need to maximise throughput and to achieve the highest possible refinery utilisation rates. Any form of plant shutdown is going to hurt profitability, particularly if that shutdown has not been carefully planned and scheduled.

Operating the refinery at maximum capacity introduces its own risks, however, and managers need to be confident that the steps taken to increase throughput do not compromise safe and reliable operations. The challenge here is to ensure that the physical assets are maintained in prime condition, that processes are optimised to maintain reliable and stable performance and that planning and scheduling decisions are made to maximise utilisation without requiring the refinery to work beyond its operating constraints.

Some IT solutions are now well established as standard tools to support reliable operational performance. Process engineers routinely use rigorous simulation technologies to analyse the behaviour of individual process units in both steady-state and dynamic conditions, and these tools play a key role in ensuring that plants are designed and operated in an efficient, safe and profitable way.

Similarly, advanced process control (APC) systems are applied almost universally on major process units to identify the optimum operating point (which in today's market is generally maximum rates), and to maintain stable operations within multiple constraints. These technologies also ensure reliable, consistent operations shift to shift, and minimise process upsets – key to reliability.

These long-proven tools are now being complemented, however, by new solutions that provide some significant additional capabilities. Advances in modelling technology have made it possible to perform rigorous simulations of multiple refinery units within a single flowsheet, so that the complex interactions among the units can be analysed in detail using consistent data and models. Multi-unit refinery modelling allows engineers to study potential operational changes in advance, so that they can explore whether throughput increases will lead to unsafe, unstable or unsustainable operations (see **Figure 1**).

Integrated solutions for planning, scheduling and blending are now available to help refinery managers ensure that their optimised production plans are implemented as intended. Planning and scheduling events in advance so that operations are properly synchronised enables refiners to avoid unfortunate (and costly) scenarios that require sub-optimum solutions and potential throughput reductions.

The latest integrated manufacturing execution systems (MES) also provide managers with real-time visibility of their operations, so that they have the data available to make informed decisions about the best course of action minute by minute. It also enables plant performance to be monitored against pre-determined targets so that any deterioration in results can be investigated before serious problems occur that may result in reduced operations reliability.

Clean fuel requirements

For most refineries in Europe and North America, the new clean fuels standards being rolled out during the current decade have led to the most significant changes in configuration, and have required the greatest outlay of capital expenditure. Even though most of the legislation has been focused on these two regions, the repercussions have been felt globally, shifting the patterns of supply and demand and reducing the product pool that is available to meet the rising domestic demand in the US and Europe.

In operational terms, refineries have needed to identify the most effective way of upgrading their equipment to meet the new product specifications while minimising the necessary investments and ensuring that production is maintained with the least possible disruption. The need to consistently achieve sulphur levels of less than 10 ppm in both petrol and diesel has also required new operating strategies and, in circumstances where regional demand is for multiple different product specifications, more complex production and blend schedules have been necessary.

The introduction of additional desulphurisation equipment has also created significant additional demand for hydrogen in the refinery. Meeting this demand at an acceptable cost has become an important challenge for process engineers working on the revamps.

IT solutions can provide valuable tools to support decision making during the different stages of defining and implementing a strategy for meeting the clean fuels requirements. New integrated planning tools make it possible to quickly evaluate capital projects, and study the alternative exchange and supply agreements and distribution plans that could support production of the new specifications.

Integrated front-end engineering and design (FEED) solutions, incorporating simulation, optimisation and economic evaluation technologies, enable engineers to analyse different revamp scenarios and generate optimum process designs for the chosen alternative. These solutions are based on collaborative engineering platforms to ensure that major projects of this kind can be carried out more efficiently and with fewer errors, by allowing all participants – including external engineering contractors and equipment vendors – to use consistent data and models.

The integrated planning, scheduling and blending solutions described earlier can play a major role in enabling refineries to reliably schedule and execute the new production and blend schedules as the new product specifications come onstream.

To help refiners manage the hydrogen demand for new hydrotreater or hydrocracker units, simulation and optimisation tools are now available that will identify the most efficient hydrogen supply and recovery schemes. By modelling the entire hydrogen network, including the different consumers and recovery units, it is possible to calculate an optimum scheme that fits within the current refinery constraints and also supports potential future changes to the refinery configuration.

Energy costs and emissions targets

Energy costs have always been an important cost driver for the petroleum industry and, with the recent major rises in energy prices, can now account for over 60% of the total operating cost (excluding crude oil purchases). Managing energy costs effectively will only grow in importance as deregulated utilities markets and uncertainty of future energy costs increase the volatility and complexity for refiners.

In parallel, there is now much greater concern over environmental performance, particularly regarding gaseous emissions such as SO_x (sulphur oxides), NO_x (nitrous oxides) and CO_2 (carbon dioxide). In Europe, the new EU greenhouse gas emissions regulations have resulted in CO_2 emissions quotas for individual energy intensive production sites and have created a market for CO_2 trading. As the utility and energy systems are often the major source of SO_x, NO_x

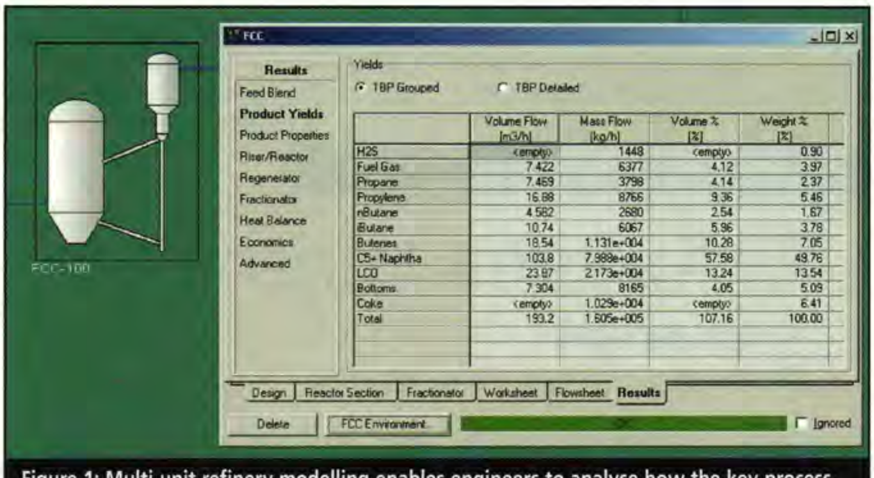


Figure 1: Multi-unit refinery modelling enables engineers to analyse how the key process units will respond to operational changes, so that unstable or unsafe conditions can be identified in advance

and CO_2 emissions, the control of these emissions and management of credits are inextricably linked with energy management.

Traditional approaches to energy cost reduction have included the application of APC technologies to operate process units in a more energy efficient way, and the use of simulation and optimisation tools to produce more energy efficient process designs. While these methods are still valid, they do not fully address the complex issues related to site-wide energy costs.

The answer lies in a new generation of integrated solutions for energy performance management. These solutions are based on accurate simulation models of a site's key process units and utility systems, incorporating the true operating constraints and cost information, so that users can visualise exactly how changes in operating strategy or utility supply will impact their energy system performance. This knowledge can be applied to real-time operational decisions, to optimise energy use and identify the lowest cost operating strategy taking into account demand, equipment availability and other operational constraints.

Data from these solutions is also to manage gaseous emissions, providing visibility of current and projected emissions levels and supporting informed decision-making about trading emissions credits.

Changing product mix

While refiners continue to benefit from a healthy increase in overall demand, this situation is made more complex by a shift in the global demand mix, with demand for certain products growing quickly and others experiencing slower growth or decline. In Western Europe, this is typified by the growing popularity of on-road diesel fuel and the relative decline in use of gasoline, which has created an increasing imbalance between refinery configuration and demand.

When combined with high crude oil prices, this places increased emphasis on the ability of companies to select the crude that has the potential to generate the greatest margin for each particular refinery while still producing the desired mix of products. Along with the rise in prices, the differential between sweet and sour crudes has also increased, and there is greater incentive to buy and run more challenging feedstocks that push the refinery operation up against multiple constraints.

In the current environment, there are opportunities to gain a commercial advantage by running more synthetic and heavy crudes, as well as crudes with high total acid numbers (TAN). These crudes cannot be run alone, however, and must be blended with other crudes, so it is essential that refiners can manage feedstock inventories and qualities to achieve the benefits of increased margins by running these non-traditional feedstocks.

Once again, integrated planning, scheduling and blending solutions play a critical role in helping refiners make the most favourable crude purchasing decisions, and to execute the production and blend schedules required to capitalise on those purchases. These solutions also make it possible for the trading organisation to have a clear and accurate picture of the operating constraints within the refinery – utilising the same data and models used by the planning and scheduling groups – so that transactions can be made more quickly, with a full understanding of the financial and operational impact.

Facing the future

In a high margin environment, it is essential for refiners to take advantage of the favourable economic conditions while achieving reliable operations at maximum throughput. Although the industry still faces some significant challenges, a broad range of integrated IT solutions is now available to help refiners improve their business processes and ensure capture of incremental margins.

Those companies that develop flexible, integrated systems to capture the current opportunities will be well placed to survive whatever changing conditions the industry faces in the future. ●

Model Code of Safe Practice Part 15: Area classification code for installations handling flammable fluids (3rd edition)

Essential reading for HSE managers and all those involved in the hazardous area classification of installations handling flammable fluids.

IP15 is a well-established, internationally accepted Code which includes a demonstrable methodology for specifying hazard radii. This new edition provides clarification on issues which have been raised by users of the 2nd edition published in 2002. It gives guidance on the classification of regions around equipment handling or storing flammable fluids, and provides a basis for both the correct selection of fixed electrical equipment and the location of other fixed sources of ignition in those areas.

The guidance given in this Code is applicable internationally to installations in processing, distribution, production and retail sectors. It applies dispersion modelling to the calculation of hazard radii, taking into account variables such as pressure of release and the effect of mist or spray formation. The current methodology takes account of both the composition of the material released and its release conditions including the release pressure. The Code also provides a risk-based approach for specifying hazardous areas from secondary grade sources of release, allowing further flexibility in specifying hazard radii.

July 2005 **ISBN 0 85293 418 1** **Full Price £105.00 (25% discount to EI Members)**

Code of practice for the development of a response plan for significant incidents involving petroleum road tankers (2nd Edition)

Essential reading for petroleum tanker operators, distribution facility operators, safety managers and Dangerous Good Safety Advisers, the emergency services and other stakeholders, as well as all those involved in the handling of significant incidents such as vehicle recovery and oil spill clean-up contractors.

Petroleum road tanker operators have a legal responsibility under the Carriage of Dangerous Goods and use of Transportable Pressure Equipment Regulations and the European Agreement concerning the Carriage of Dangerous Goods by Road (ADR) to have in place a response plan to protect their employees, the public, property and the environment in the event of accidents or incidents involving the carriage of dangerous goods.

The guidance set out in this updated Code is suitable for those with large fleets operating on a national basis or small enterprises with a few petroleum road tankers operating in a limited local area. Response plans developed using this Code should match the scale and nature of those operations and should cover foreseeable scenarios where a petroleum road tanker has been involved in a significant incident, possibly overturning and spilling product that may impact a third party, property or the environment. To assist companies in developing their own plans, the Code sets out some generic procedures. The Code should help companies to better understand, but not to take over, the roles and capabilities of the emergency services and other stakeholders in significant incidents. It may also be used as a point of reference by the emergency services and other stakeholders as it sets out good industry practice in handling significant incidents. Adoption of the Code should therefore establish a common approach across the petroleum industry to significant incident response and enable the emergency services to plan for a known level of industry assistance.

June 2005 **ISBN 0 85293 438 6** **Full Price £81.00 (25% discount to EI Members)**

Guidance for safer design of offshore installations: an overview

Essential reading for project managers, operators, contractors and all those involved in the safe design of offshore installations.

The greatest opportunity to achieve a step improvement in safety in any operation is during design. This has been recognised by industry and its safety regulator, the Health and Safety Executive (HSE). Recognising this opportunity and the possibility of reducing the occurrence of adverse findings in offshore installation design safety cases, UKOOA and HSE established a Safety in Design Working Group. The Working Group commissioned this guidance to be a tool to help achieve those objectives and promote awareness.

This brief guidance is set out under 12 Design Safety Elements such as inherently safer designs, residual hazard management and technical integrity. Each Design Safety Element includes expectations and details of what should be addressed. These are further illustrated using case studies, key points, lessons learned and graphics.

IP Guidance for safer design of offshore installations: an overview is intended to help project, operating company and contractor managers and other senior staff involved in design to play a part in achieving a step improvement in inherently safer design of off-shore installations, both for new projects and major modifications. The aim is to achieve simplification, and in many cases lifecycle cost reduction by taking a more aggressively radical approach to offshore installation design. This should also reduce risks to those working on offshore installations.

June 2005 **ISBN 0 85293 446 7** **Full Price £32.00 (25% discount to EI and UKOOA Members)**

Please quote marketing code 'PR2005' when ordering these publications

Order from Portland Customer Services, Commerce Way, Whitehall Industrial Estate, Colchester CO2 8HP, UK. t: +44 (0)1206 796 351. f: +44 (0)1206 799 331. e: sales@portland-services.com

www.energyinst.org.uk

Coal bed methane to help meet rising coal demand

China's rapid economic development during the past decade has been accompanied by a large increase in coal consumption, which the domestic mining industry has struggled to keep pace with. In spite of plans to diversify the country's energy sources, coal will remain the major fuel source for the foreseeable future. Already this is presenting the Chinese government and coal industry with the major challenge of how to deal with the vast volumes of methane gas being released during mining operations. David Hayes *reports.*


Photo: David Hayes

Shanghai skyline, China

Coal is China's largest single source of energy. According to government figures, it accounts for 65% of primary energy demand, while oil is about 24% and natural gas 3%. Hydroelectric power, nuclear power and renewable energy make up the remaining share.

Coal-fired power stations produce about 75% of China's electric power generation. Hydroelectric power represents around 20% of power output, while oil, gas and nuclear power plants supply less than 5% of the nation's electricity needs.

According to official forecasts, despite the planned increase in natural gas use following the recent completion of the West-East gas pipeline and the planned construction of a series of LNG terminals along the east coast for importing gas, coal will remain the dominant fuel in China's primary energy mix. In 2015, coal is forecast to account for about 64% of the nation's primary energy consumption and 75% of electricity generation.

While coal users are urging mine operators to increase coal supplies, China's coal mining industry is producing vast quantities of methane gas – which is causing problems as a greenhouse gas and as a major hazard for coal mining safety. According to international estimates, Chinese coal mines vent between 10bn and 12bn cm/y of methane into the atmosphere. At least some of this methane could be captured and used as clean energy if the coal industry were properly encouraged to develop coal bed methane production and utilisation schemes as viable commercial business ventures.

Methane emission rates are large as coal production in China is mainly underground. Only about 5% of coal produced is by open cast mining. Indeed, the volume of methane produced is rising as coal output expands and mining is extended to greater depths.

Methane present in coal is called coal bed methane (CBM) when released through purpose-drilled wells. Methane that escapes into the atmosphere through coal mine shafts is categorised as coal mine methane (CMM). At present, almost all methane released through coal mining activities in China is classified as CMM as very little is captured for use as clean energy.

Methane is absorbed onto the internal surface of a coal seam and is released as a result of pressure changes when underground coal is mined or exposed to surface conditions. Underground CMM is highly explosive and needs to be removed during, or sometimes before, coal mining operations in order to ensure safe working conditions.

Safety – a growing concern

Safety is a growing issue for China's coal mining industry as domestic and international publicity steadily increases about the high death and injury toll caused by inadequate safety measures and coal mine managers' apparent disregard of miners' safety in pursuit of higher production earnings.

China produced 35% of the world's total coal output in 2004, but recorded 80% of global colliery deaths. According to official figures, 6,027 people died in explosions, floods and fires in China's coal mines in 2004. The death toll from 3,639 accidents last year was 6.3% lower than fatalities reported in 2003. Many Chinese coal mines – particularly in Shanxi, Henan and Guangxi provinces

Photo: David Hayes

Streets of Shanghai

– have a high methane content. Inefficient methane drainage is a major cause of frequent underground explosions. An average of 15 miners died each day during the first nine months of 2004. Following a gas explosion at Chenjiashan mine in Shaanxi province in November 2004, in which 166 miners died, China's ruling State Council ordered an inquiry as newspaper articles called for a more humane approach to economic progress.

Commercial potential

China's CBM development potential is large due to the country's enormous coal reserves. Total CBM resources at a depth of up to 2,000 metres are estimated at between 30tn and 35tn cm. Based on experience in the US, about 10% of Chinese CBM resources – equal to between 3tn and 3.5tn cm – could be developed into proven reserves, which could be produced through surface wells and used as fuel. This volume of methane is equivalent to about 100 years of China's current natural gas production rate.

The government has already enacted various preferential policies to encourage coal mines to increase CBM capture and use. Some coal mines use CBM for small-scale power generation or supply it by pipe to households. However, CBM use is small and less than 10% of vented CBM has been properly drained.

Currently, the government provides preferential policies and tax incentives for private investors who wish to undertake CBM exploration and production in virgin coal areas. In addition, China United Coalbed Methane Corporation was established in 1996 to attract foreign investors and technology to develop China's CBM sector. China United's intended role is to be a joint venture partner for CBM exploration and production activities.

CBM development has been limited despite official support. Although foreign oil and gas companies are estimated to have invested over $90mn in CBM exploration and development activities, until now a successful CBM development project using surface wells drilled into virgin coal seams still has not been developed on a commercial scale in China.

International support

As part of international efforts to support development of China's huge CBM reserves, the Asian Development Bank (ADB) recently approved a $117.54mn loan to establish a commercial CBM scheme in Shanxi province in northern China – a major coal producing centre which has highly methane-rich coal mines. The project also is being supported by a $20mn loan from the Japan Bank for International Cooperation, while the United States Trade and Development Agency (USTDA) is providing a $500,000 grant to finance consultancy services for the construction of a CBM-fired power plant that forms part of the overall project.

To be implemented by Shanxi provincial government in Jincheng in the south of Shanxi province, the project is planned as a demonstration of new technologies to develop and supply CBM methane gas that will act as a catalyst for the development of other similar CBM projects elsewhere in China. Coal mine operators and other organisations interested in investing in CBM development are expected to visit the project to learn how to implement their own CBM schemes.

In addition to demonstrating more efficient production techniques for CBM drainage and capture than have been used in China until now, such as directional drilling, the project will show the use of CBM as a least-cost solution for power generation using new technology, and the efficient commercial use of CBM for piped distribution to industrial, commercial and household consumers.

'The coal bed methane project is starting for environmental reasons and for energy efficiency. Also, for mine safety by drilling to release the methane. Why lose all that gas?' said Anil Terway, Energy Division Director in the ADB's East and Central Asia Department. 'CBM development is meant for large mines, with high grade coal with a high carbon content that is deep, and methane which is released when disturbed. We will introduce directional drilling with this project, which also will fuel a power plant.'

The Jincheng CBM project consists of building a piped gas transmission and distribution system to supply gas to customers in the Jincheng area and construction of a 120-MW power plant to burn CBM. In addition, consultancy services will be provided to support development of the organisation charged with operating and managing the Jincheng CBM gas utility system. Separate companies have been set up by the Shanxi provincial authorities to own and operate the gas transmission and distribution system, and the gas-fired power plant.

Development drilling of the methane reserves will be undertaken with assistance from experienced international experts. Should the CBM reserves allocated for the Jincheng project prove problematic to fully recover, Shanxi provincial government has agreed to make additional CBM methane supplies available from other nearby producing CBM reserves.

According to Terway, the Jincheng CBM scheme is expected to supply about 265mn cm/y of methane, replacing the equivalent volume of polluting fuels now in use such as wood, coal, synthetic gas and petroleum-based fuels. In addition, the scheme will save 430,000 t/y of coal, of which 300,000 tonnes will be saved by using methane rather than coal to fuel the power plant, with 130,000 tonnes saved by industries switching from coal to burning methane.

Other benefits of the project will include the consequent reduction in greenhouse gas emissions, while particulate matter, sulphur dioxide and nitrogen oxide emissions will be reduced by replacing coal use with methane. In addition, the Prototype Carbon Fund has agreed with China's Ministry of Finance to purchase 3mn tonnes of carbon dioxide equivalent in emission reductions at a unit price of $4.25/t for a total contract value of about $12.75mn.

Benefits will also be gained by poorer members of Jincheng's local community. The project developers will connect poor households free of charge to the piped gas distribution network. Customers classified as living in poverty will be charged 50% of the normal monthly gas user tariffs.

Supply shortages

Meanwhile, the mining industry is unable to expand production sufficiently to keep pace with China's fast growing energy requirements. Although coal production is forecast to grow this year, coal supply shortages will continue in 2005 – causing further electricity generation shortages, particularly during the summer months.

According to China Coal Industry Association, coal consumption will grow by 120mn tonnes, equivalent to 6%, in 2005 – to reach 2.1bn tonnes. In fact, coal use will increase by half the rate recorded in 2004, when coal consumption rose 12% to reach a record 1.98bn tonnes. Imports will rise to cover part of the increase in coal demand, as China's coal production cannot grow by more than a maximum of 100mn tonnes in 2005 despite the opening of several new coal mines. A lack of large new coal mine projects is the main factor holding back any immediate substantial increase in coal output.

Official forecasts for total domestic coal output this year are still awaited after coal production reached 1.96bn tonnes in 2004. Last year's output figure recorded an increase of 225mn tonnes, equivalent to 13.2%, compared with an output of 1.73bn tonnes in 2003.

China's coal shortage has been caused by rapid energy demand growth, in particular fast-growing electricity consumption by industrial users and rising residential power consumption as households purchase more home electrical appliances. Power stations burn about two-thirds of China's total coal output. According to government figures, electricity consumption has grown by 15% over the past two years. A significant proportion of additional electricity demand is coming from the growing, energy-hungry steel, cement, aluminium and automobile industries.

The government has designated five sectors to be given priority access to coal supplies this year in order to ensure China's economic development is stable. The sectors are power generation, fertiliser production, steel production, private residential consumers and the coal export sector.

Actual coal demand in 2005 will depend on how effective the government's attempt to rein back rampant investment in energy-hungry industries proves to be. After restricting bank lending to targeted sectors last year to cool down over-investment in steel, cement and aluminium, the government recently suspended construction of 20 power plants, saying they had not been designed to comply with required environmental standards.

China's domestic internal transport constraints are also causing problems, with coal stockpiles growing at some mines due to insufficient rail wagons being available to transport coal to power plants and other consumers.

Most of China's coal is produced in the north, while energy demand growth is highest in the eastern and southern coastal provinces. In eastern China, only a small number of provinces – including Anhui and Shandong – produce coal, while others – such as Jiangsu and Zhejiang provinces, and Shanghai – produce little coal but are among China's largest coal consumers.

Some energy analysts believe that China's coal supply problems will be eased partially in 2005 due to a number of transport constraints being resolved with the operation of additional freight rail routes. However, others note that uncertainty still remains as not all coal supply contracts have been completely agreed under China's centralised coal supply allocation system.

Contracts for more than 900mn tonnes of coal were concluded at China's annual coal ordering conference earlier this year. The tonnage represents an 80mn tonne increase compared with the previous year, according to the Coal Industry Association.

Supplies under so-called 'key contracts' increased by 30% to 618mn tonnes. Key contracts allow users to enjoy lower government-subsidised prices, although most contracts signed are for tonnages only and do not specify prices. The contracts are signed to help arrange transport and are not binding as the contracts may not be executed if the contracting parties do not agree coal prices in due course.

In fact, the government intends to improve the efficiency of China's coal buying and selling supply system, and to establish a coal exchange centre to replace the annual coal ordering conference. China Coal Industry Association, power companies and coal transporters have been instructed to provide the government with more detailed information on coal supply and demand to enable the proposed coal exchange centre to be established.

A stimulating time

Reservoir fracturing has become a very important tool for increasing hydrocarbon output. Gordon Cope *looks at some new developments.*

Photo: Halliburton

Halliburton set an offshore, deepwater record for high-pressure fracturing in 2004, in the Gulf of Mexico

In October 2004, Halliburton achieved a world record when it successfully performed a fracture stimulation on a well in the Gulf of Mexico – in 4,100 ft of water and 25,812 ft total depth. The technicians at Halliburton were understandably proud of their achievement – the task underscored a trend that has pushed the boundaries of reservoir stimulation into regions and applications that could only be imagined a decade ago.

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 (the amount of hydrocarbon that flows to the wellbore) by several orders of magnitude. This allows a faster return on capital investment and ensures that the well produces more.

Fracture stimulation was first devised after the Second World War to help coax hydrocarbons from low permeability formations. 'Guys were pumping diesel fuel down,' explains Greg Salerno, a Manager for BJ Services, one of the world's largest suppliers of stimulation services. 'They got more production until the channels closed up.' The technique was slow to catch on – most producers simply ignored poor reservoirs and concentrated instead on targets that produced higher yields naturally. But the maturation of most of North America's basins, the subsequent peak (and decline) of domestic production and, most importantly, the high price for natural gas, has meant a refocus upon fracturing. 'Around 80% of wells drilled in North America are gas wells – about 24,000 wells,' says Salerno. 'About 80% of those are fractured – around 20,000 wells.'

Cost versus payback

The cost of a fracture job can start as little as \$25,000 or run in excess of \$1mn, depending on the distance of the well from a service base, onshore versus offshore, the pressure needed, the number of zones treated, and the materials used. The decision to fracture a well is based on cost versus payback (the time it takes to cover the cost). 'Fracturing increases the amount of gas by two to four times,' says Salerno. As a typical example, he cites an area in Texas in which wells traditionally produce at 4mn cf/d. 'A client had a well come in at only 2.5mn cf/d. We did a fracture stimulation, and it produced at 10mn. Ideally, the payback comes within one or two months, but I've seen as little as 14 days and as long as six months.'

The technique is not without its problems. Rumours concerning over-stimulation in the FSU that have led to serious damage to reservoirs continue to circulate. Service companies note that, especially in new basins, there are indeed risks to fracturing a well. 'The first 20 wells in a completely new basin, you can't claim a tremendous success rate,' comments Salerno. 'After 20 fracture jobs, there is enough of a database that the success rate is close to 100%. Even if you're in a basin that's never been fractured, but the basin is identical to others that have, you can transfer engineering data.'

Producers in mature North American basins – where approximately 70% of the world's fracturing jobs are performed – are eager to employ the technique. 'Activity was up 40% to 50% in 2004, and it's up 15% to 20% in the first quarter of 2005,' says Richard Marcinew, Schlumberger's Engineering Manager for its Canada well production services. While much of this activity is associated with shallow wells, more and more attention is being focused on deep wells where drillers encounter hotter temperatures and higher pressures. And that means innovation.

Innovative developments

At its simplest, fracture stimulation requires only fluid, such as diesel or water, and a surface pump to generate the approximately 5,000 psi pressure needed to make a reservoir crack. In practice, however, the search for higher conductivity over longer periods of time in more exotic reservoirs has motivated service companies to come up with new types of fluids, proppants and fracturing techniques.

When the pioneers of stimulation first realised that fractures would produce better if they were propped open with something, they began to cast about for a suitable material. Their search led to

Ottawa sand, used in the construction industry to make cement. It was highly spherical, strong and, most importantly, cheap. 'Most proppant used for fracturing in North America is Ottawa sand (also known as white sand),' explains Salerno. Unfortunately, the construction industry is currently consuming most of the production. 'Right now, there's a shortage of Ottawa sand because the mines can't produce at the rate we need. The price is going up and availability is going down.'

This has motivated various service companies to tinker with alternative materials. 'Brown sand is available, but it has lower roundness and conductivity,' notes Walt Glover, Halliburton's Senior Supervisor of Marketing Communications. The Houston-based service company alleviates these shortcomings by coating brown sand with a special resin mix to improve the material's properties. 'Our proppant coatings will make brown sand as appropriate to use as white sand. You can [even] get better performance.'

For its part, BJ has turned to the agricultural sector for inexpensive alternatives. 'We have invented a new product, LiteProp, with a specific gravity close to water,' says Salerno. 'It's made of walnut [shell] coated with resin. It can handle stress up to 6,000 psi.'

Proppants are also being manufactured entirely from artificial ingredients. 'VersaProp is an intermediate strength ceramic proppant made of bauxite and silica,' says Glover. 'You are able to put more pounds into the fracture width. It has a higher conductivity than lightweight proppant.'

Although they are more expensive than white sand, artificial proppants can be customised to higher temperature and pressure usages. 'Depending on the closure stress, you might need a very high strength proppant, something like bauxite, which is strong, but heavy [dense],' notes Salerno.

Gumming up the works

The problem with stronger, denser proppants, however, is that they prematurely settle out of the fluid used to transport them down to the fractured formation. 'You need to make the fluid more viscous so that it has carrying capacity to the reservoir,' explains Salerno. 'You use a polymer-laden fluid.' While it might sound rather high-tech, most polymers used in stimulation can, in fact, be found in muffins and other baked goods. 'A lot of polymer is made from Guar, which is a bean grown in India,' says Salerno. 'Sometimes there's a drought in India and there's not enough Guar. Then we use Xanthan gum, which is a starch polymer.'

In a typical fracture, a series of trucks carrying hundreds of thousands of gallons of water assemble at the hole. One truck carries concentrated polymer. Water is pumped down to fracture the reservoir. The polymer is then added, and the water and polymer mix as they descend in order to minimise friction on the way down. The proppant, as much as 50,000 kg, is then added. Ideally, the water and polymers mix and reach sufficient density at the base of the hole to carry the proppant in suspension into the fracture, where it settles out.

Once the proppant is in place, the polymer must be cleansed away. 'If the fluid is too viscous, it starts to gum up the reservoir,' notes Salerno. 'You need to break up the polymer with bleach or an oxidant.' Chemical agents tend to deplete rapidly, however, leaving the area closest to the hole clean, but the far tip of the fracture still plugged. 'Now, we're using enzymes to break the polymer bonds. One molecule of enzyme will break 100,000 polymer connections,' says Salerno.

Schlumberger has eschewed polymers in favour of enhanced viscoelastic surfactant fluid. 'A surfactant associates with hydrocarbons at one end and water at the other,' explains Richard Marcinew. 'It associates itself into long structures like spaghetti, and viscosity develops. It transports the proppant well, but, being a surfactant, there are no solids to plug the permeability, so you have 100% retained conductivity.' Schlumberger's original versions, which were applicable to 200°F, have now been strengthened to perform at 300°F and in a carbon dioxide (CO_2) rich environment.

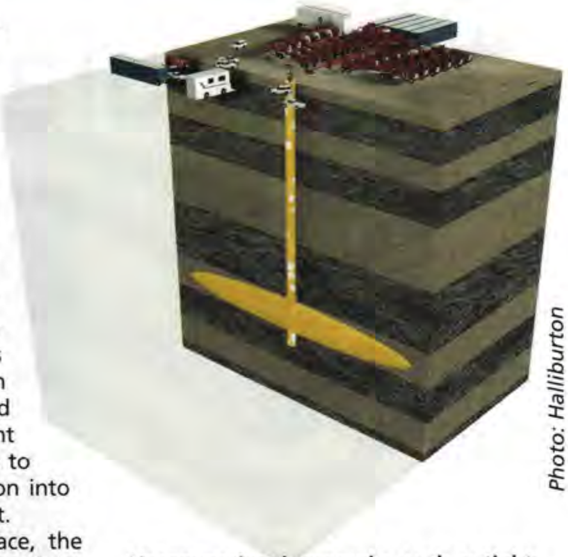


Photo: Halliburton

Unconventional reservoirs, such as tight sands, require comprehensive fracturing to produce

Fracturing the reservoir, pumping the proppant to the fracture and cleaning up the fluids is only part of the task, however. All too often, the reservoir formation wants nothing to do with its new inhabitants. 'If you have high formation pressure, it wants to push the proppants back out,' says Salerno. Service companies have thus come up with various ways of ensuring the proppant remains where it is supposed to. 'We have a proppant called Flex Sand that deforms slightly under pressure,' notes Salerno. 'You mix in a bit and it locks the rest of the proppant in place.'

Halliburton has come up with a resin

Photo: Halliburton

Fracturing requires a wide variety of equipment – pumps, fluid tankers, polymer tanks and proppant

called Expedite that can be applied to the proppant so that the particles stick together like glue once they are in the fracture. According to Glover, the mixture has superior conductivity under stressful conditions. 'We looked at the cumulative production histories of four wells in the Gulf of Mexico, two with the Expedite and two without. The two with had a conductivity larger by a factor of three over a 12-month period.'

All of the innovations are tested to the limit when a hole encounters very high-pressure formation conditions. 'Very high pressure is generally considered anything over 15,000 psi on the surface,' says Salerno. 'There's not too much of it done, one in Colorado at 17,000 psi, one in South Texas scheduled at 18,000 psi. You see some in the Anadarko basin, mid-continent.'

And in the Gulf of Mexico. When Chevron drilled Green Canyon 640 No 1 to a depth of 25,812 ft, the company encountered a reservoir formation with a fracture pressure in the order of 22,500 psi. It called upon Halliburton's Production Optimization Division to help with the fracture stimulation. 'We needed in excess of 16,000 psi surface pressure,' recalls Wes Ritter, Halliburton's Senior Technical Adviser for deepwater completions. 'But most fracture equipment, such as lines, are limited to 15,000 psi.'

Halliburton's solution was to use the fracture fluid to aid in pressurising the bottom of the hole. 'We have a fluid system that was new in 2004,' says Harvey Fitzpatrick, Halliburton's Sand Control Product Manager. 'It's called DeepQuest and is a densified, single salt brine with a specific gravity of 1.3–1.38. It has a higher hydraulic head at the fracture which reduces surface treating pressures.' In other words, Halliburton could augment the 15,000-psi surface pressure with the weight of the fluid column itself to crack open the reservoir. The job was a roaring success and, thanks to Halliburton's work, the well is expected to flow in excess of 30,000 b/d.

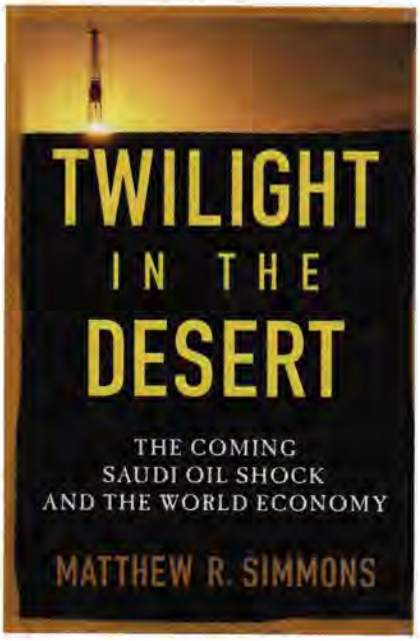
But very high-pressure wells are only a tiny percentage of the stimulation business. The major market for fracturing is currently in thick, low permeability sands that require special attention in order to create and maintain conductivity. To that end, Schlumberger has devised a fibre technology that transports the proppant then rots away. 'It's a synthetic fibre about 1/2-cm long and the thickness of a few hairs,' explains Marcinew. 'The fibre carries the proppant down, helps it settle in then dissolves over time, from a few weeks to a few months, depending on the temperature. You end up with higher permeability in the fracture, and it doubles conductivity. It's good for large, thick formations where it's difficult to distribute proppant evenly. EnCana's been using it in the US in the Rocky Mountains. Now, they're going to use it in northern Alberta.'

As far as the future of fracture stimulation is concerned, prospects are bright. 'Coal bed methane is huge,' notes Marcinew. 'There are going to be over 3,000 wells this year, and all are fractured.'

'A trend that has already started and will go on for many years is going into an existing well and maximising returns,' says Glover. 'You go back in and identify zones and do pinpoint stimulations.' Halliburton expects that the trend will extend far beyond North America, to regions where major fields are entering into decline but still have huge remaining reserves. 'The best place to find oil is where you already found it,' says Fitzpatrick.

Twilight in the desert

Houston-based Energy Banker Matt Simmons *recently launched the publication of his book* Twilight in the Desert. *His stated hope is that the book will serve as a wake-up call on the urgency and importance of understanding the limits, not just to Saudi Arabia's oil, but to the entire world's oil supply, as he maintains we are clearly approaching the peaking of oil supply at the same time as the world faces a relentless increase in oil demand. The following is a shortened version of the speech he gave at the book launch in Houston on 8 June.*



Twilight in the Desert spells out the risks of a pending Saudi Arabian oil shock and its potential impact on the world economy. The evidence supporting this warning is laid out in 400 pages of detailed evidence. The book's bibliography lists over 250 sources of information, including 235 technical papers downloaded from the Society of Petroleum Engineer's digital library. The authors of virtually every paper were technicians/engineers employed by the Saudi national oil company and/or senior technicians working in the actual oil fields that produce virtually oil of Saudi Arabia's oil.

The warning that the book spells out is not a certainty. It is simply my best educated estimate following two years of in-depth research into Saudi Arabia's oil system, which was grounded by three decades of studying and analysing the oil and gas industry.

Warning message

The book's most important message is a warning – analogous to a warning that a treacherous hurricane is brewing in the Gulf, or the warnings we used to face about the threat of thermonuclear war. People can do two things with warnings – ignore them or heed them. Prudent people usually pay close attention to warnings and take them seriously.

I intentionally chose the term 'Pending Oil Shock' as the subtitle for the book, but I also provide no specific date on when it might occur – analogous to Churchill's steadily increasing warnings throughout the 1930s of pending war, the date of which he could never pinpoint. Two weeks ago, I read the last key speech Churchill delivered on the high probability that war would occur. It was delivered less than a week before Hitler invaded Poland. And, like all his other talks, most people shrugged off this last warning as one more boring, tedious, pessimistic and dark view. Ignoring his warnings became a colossal global mistake.

For the past 15 years, I have been an increasingly vocal worrier that all was not well in oil and gas world. I grew increasingly convinced that conventional energy wisdom was getting the energy blueprint wrong as the 21st century began – just as wrong as industry experts did in the early 1970s when low oil prices lulled the entire world into devouring all spare capacity and sending oil prices spiralling. Or, as wrong as conventional wisdom was in 1980 when many of these same experts, convinced that prices were headed to \$100/b or more, overspent so enormously on expanding drilling capacity that it took a decade-long oil depression to finally rebalance the oil market. That was the era which brought Houston to its knees.

At least a decade ago, I concluded that we had too few drilling rigs, which were also rapidly aging, and I grew increasingly alarmed that industry opinion setters were overly giddy about the impact that modern oilfield technology was having on making supply additions easier. I, instead, warned that this technology was creating monster decline rates in too many oil and gas fields. I constantly worried that oil and gas demand was far more robust than most experts assumed and that one day, out of the blue, it was likely that both oil and natural gas demand would silently begin surpassing daily supply. Having lived in the first row of the 1973 and 1979 oil shocks, I know how devastating it can be when demand for a scarce resource suddenly exceeds supply.

The more I studied these energy issues, the more serious they appeared. And, as my research intensified, I never ceased to be amazed at the number of senior industry executives, energy analysts and economists who seemed certain that my energy analysis was dead wrong. Energy optimists are terrific people, but they generally lack any data to support their energy beliefs.

Digging deeper

As I dug deeper into all the energy facts in the public domain, I also became increasingly concerned about the poor quality of most of our energy data. My biggest data puzzlement was the total lack of any verified data on Middle East oil. While virtually every oil expert in the world has believed that Middle East oil is so plentiful and equally inexpensive that it is essentially inexhaustible for the next 30, 50 years or even 100 years, no one I ever met had any real facts to support this conclusion. The concept was either pure optimism, or based on readily available numbers that had not been audited. This boundless Middle East oil belief, however, anchored all of the optimistic views that cheap oil would last forever.

Over the past decade, I would occasionally pose a simple question, such as: 'How many oil fields produce all the oil in the Middle East?' Or 'What are the Middle East's top ten producing fields?' Not one of these apparent oil experts ever seemed to know any of these basic details. But, these same people were certain that the Middle East's oil resources were so vast that even questioning these details was considered trivial and unimportant. And, when discussing the Middle East in general, everyone always (and appropriately) pegged Saudi Arabia as the epicentre of the Middle East's vast cornucopia of oil.

Four years ago I embarked on an in-depth research project to attempt to compile a list of the world's largest oil fields. The end result was a White Paper I entitled: 'The World's Giant Oil Fields'. It listed all the global oil fields that still produced at least 100,000 b/d. To my amazement I discovered that the total number of fields of this size or greater was around 120, but this tiny group accounted for almost half of the world's oil supply, with the other 5,000 or more smaller fields accounting for the remaining half.

As I ploughed into the fuzzy data on the Middle East's oil fields, I discovered, to my surprise, that every single Middle East oil producing country had only a small number of aging giant or 'super-giant' oil fields that accounted for virtually all of each country's current oil production. Once again, this research project left me amazed that so many energy experts with such strong convictions about long-term energy supplies had no hard data to support their optimistic beliefs.

Talking to the Saudis

At the end of April 2002, an event occurred that profoundly changed how I spent the next 30 months. Herbert Hunt, a good friend of mine, called me from Dallas to ask whether I would join a group of eight businessmen and spend six days in Saudi Arabia as guests of the Kingdom. In the third week of January 2003, I finally got news that the trip was 'a go'. The six-day trip was nothing short of amazing. We had extremely educational meetings with key Saudi Arabian governmental officials and about 300 senior businessmen, educators and public health executives. The Saudis could not have been more gracious and friendly — these people were terrific! Their love for the special relationship which Saudi Arabia has shared for three-quarters of a century with the US was very real and very moving.

I was soon talking about all the odd pieces of energy data that we heard or saw that seemed inconsistent with the fact that Saudi Arabia had 90 years of proven reserves at its current rate of production and over 80 fields that were discovered, but had never been produced. I kept coming back to 'fuzzy logic' – a term one that of Saudi Aramco's executives used to explain why the company was now applying state-of-the-art oilfield technology so intensely to make sure its resource base was being managed properly. But, if Aramco's reported reserves were right, why was managing this vast oil 'fuzzy'?

Back at base

Upon my return to Houston, I began digging more diligently into field-specific Saudi Arabian oil issues. Within a month or so – thanks to a friend who lent me an article published in the *Journal of Petroleum Technology*, which described the problems being encountered in a small section of the super-giant Ghawar oil field – I soon found lurking in the semi-public domain (namely the Society of Petroleum Engineers' digitised library) hundreds of technical papers discussing the very specific problems that the handful of key Saudi Arabian oil fields were now struggling to overcome as they matured and as the water injection process increased in order to maintain high reservoir pressures to 'sweep' all the easy to produce oil from these fields.

These papers were not 'Pentagon' papers. Instead, they were all technical presentations, all peer reviewed, all approved for publication by Saudi Aramco and/or the Saudi Arabian Petroleum Ministry. These SPE papers became the basis of the information that ultimately created this book.

Throughout the spring of 2003, I digested about 40 of these papers and decided to crank out another White Paper. I went back to the SPE digitised library and downloaded another 105 papers. I ended up with an awful sense that I had possibly stumbled into a grim picture of the future course of the world's energy supply.

I then reorganised all these reports chronologically by specific field. I wanted to re-start my research on a field-specific basis, reading the oldest reports first and progressing from the earliest report number #80 that was written in 1961. I wanted to try to chart the behaviours of these key fields as time progressed and as technology coaxed these fields to produce greater amounts of oil at ever-increasing rates. I began to realise that 'we', being the entire world, might have accidentally built the world's future energy model on a bed of illusionary sand. My mounting fear was that Saudi Arabia's oil supplies were not inexhaustible, but instead were coming from only a handful of overworked, aging fields that were ALL at risk of a sudden production collapse.

Key issues

The key issues that *Twilight in the Desert* spells out are as follows. Five great oil fields have accounted for about 90% of all the oil that Saudi Arabia has ever produced. The largest of these fields, Ghawar – which is the world's largest oil field – still accounts for about 60% of Saudi's oil output. Four other remarkable giant oil fields, although less productive, produce three-quarters of the remaining oil that Saudi Arabia has produced.

These great fields have been the world's swing producer of oil for the past 35 years, ever since US oil supply suddenly peaked in 1970. But, as the saying goes 'All good things finally come to an end'. The paper-trail of decades of technical reports tells a story of an aging oil system that faces major challenges – not in growing oil output, but in safely keeping the current production from each key field from suddenly collapsing.

My research also unveiled a major discrepancy between the amount of 'proven reserves' these field were thought to have in 1979 – when the booking estimates were last done by some of 'the best of the best' petroleum engineers in the world (1979 being the last year when Aramco was run by Chevron, Exxon, Texaco and Mobil) – compared to the proven reserves these same fields were thought to have less than a decade later. In 1979, the experts put real proven reserves (under SEC definitions) in Saudi Arabia at 110bn barrels, with 176bn barrels of proved and probable reserves, and 245bn of all three 'Ps' (proven, probable and possible). Eight years later, even though no new fields of any size were found, the reported proven reserves were 260bn barrels [In the period from 1979 to 2004 Saudi Arabia has produced approximately 85bn barrels – Ed.]

Another stunning discovery this research uncovered was the sad tale of 35 years of exploration frustrations, as all but one effort to find more oil outside this small number of fields failed. They essentially came up empty.

My research uncovered an untold number of surprises. The single biggest revelation occurred after I thought I had finished the book. In the manuscript that had already been sent to the publisher Wiley, I had briefly mentioned two tiny pieces of data about two events in the 1970s when Saudi oil production was ramped up from around 3mn b/d to over 8mn b/d in 1973, followed by the embargo, an easing off of this high rate of production and ramping back up when Iran's oil output collapsed at the end of 1978.

One data point referenced an article in the *New York Times* in early 1979, written by Seymour Hersh. The article told of closed door Senate Hearings in 1974, when a stunned group of senators were told that the Saudi oil fields were being worked so hard that a cutback in output would soon be mandatory and the embargo took Aramco off the hook. I then quoted from an Executive Summary of a Senate Staff report to the Subcommittee on Multinational Corporations of the Committee on Foreign Relations, written in April 1979, which was questioning the amount of reserves in Saudi Arabia and asking whether even a 9.8mn b/d production from these handful of key fields could be sustained through the early 1990s without the most productive parts of these fields going into irreversible decline.

During compilation of the book's bibliography, my assistant, Judy, wanted to ensure all quotes were accurate and managed to locate a copy of the entire 33-page 1979 Senate Staff Report in the Library at The University of Houston. This report also contained the specific title of the 1974 closed US Senate hearings that the *New York Times*' article mentioned. Within a week, I was also in possession of the 1,390 pages of the 1974 Senate hearings and papers that this hearing obtained from the four Aramco owners under subpoena.

'Oilgate' unveiled

What these 'last-minute data finds' laid out was a story rivalling Watergate – but this time it was 'Oilgate'. It turns out that a 'whistle blower' (or blowers) from one of the four owners of Aramco had send a batch of papers to one of America's top investigative reporters, Jack Anderson, detailing a plot to produce every saleable drop of oil that the owners of Aramco could produce before the company was nationalised. To pull this off, it was necessary that Aramco's Saudi Arabian partners were convinced that these fields were so special and prolific that they had no rate sensitivity to how they were produced. Plans were laid out to ramp production up to between 20mn and 25mn b/d, even though some key people knew that this could never be sustained.

As early as 1972, various field reports written by the best experts within the Aramco group were warning Aramco's senior management that production of 8mn to 10mn b/d was threatening to collapse the high reservoir pressures that made it possible to produce such a vast amount of oil from only a small number of producing wells. In my view, it was a global tragedy that this knowledge ended up being concealed from public view.

Had the oil crisis in 1973 not abated, had Watergate not been steadily escalating as all these 1974 hearings were occurring, had the senior Aramco owner executives not testified under oath that rumours of any Saudi oilfield problems were highly exaggerated, three decades ago the world might have begun to accept the reality that Middle East oil was not some magical fountain of inexpensive, inexhaustible gushing energy.

Had the world known the limits to Saudi Arabia's oil output while we still had 25 to 30 years to better prepare for a peaking of sustainable oil, Houston would have likely also been spared the agony of the oil depression. But, based on a false belief that we had a 15mn or even 20mn b/d shut-in oil supply, the oil industry collapsed – destroying 90% of the oil service sector and 28 of Texas' 30 largest banks. A decade-long energy depression was created by the false concept that the world had this massive shut-in excess energy supply.

Had the world started to grasp the knowledge that *Twilight in the Desert* will hopefully now impart, I suspect that oil prices at the end of the 1970s would have stayed high enough to begin opening the door to new forms of energy and using devices that were far more efficient. Instead, the world entered an energy fantasy land and began assuming that cheap oil and gas could grow as fast as demand ever dictated.

The background surrounding the April 1979 33-page Senate Staff Report is still somewhat of a mystery. But, buried in this report was knowledge that the three great oil fields of Saudi Arabia that produced virtually all the Arab Light and Extra Light oil would go into irreversible decline by the early to mid-1990s if their 1979 production rate was maintained.

Don't panic

It is vitally important for people to understand that passing sustained peak oil output does not mean that the world, or Saudi Arabia, has suddenly run out of oil. To confuse 'peaking' with 'running out of oil' is naïve and the equivalent of not understanding the difference between being hungry and the risk of starving to death.

Since this risk is real, my first recommendation is for everyone who cares about this issue to begin clamouring for a reform in the way in which all significant oil producers report their oil production data. The world desperately needs timely and verified field-by-field production reports from all key suppliers and also a sister report of the average number of well bores from each key field, along with proven reserve data by field. This reform needs to include all national oil companies, not only Saudi Aramco. The reform needs to also encompass all our significant public oil and gas companies.

Such data reform could be instituted in a matter of months, as all key companies in the world already maintain this data somewhere – even though most companies never aggregate the data and few senior managers ever look at the results. The new era of 'good data' also needs some third-party audit that the numbers are real.

Armed with such data, in my view, it would take a group of 30 intelligent analysts a mere 30 days to sort through the world's top 200 oil and gas fields and finally produce a model based on genuine historical facts on the likely production profile over the next three years – just like Simmons & Company's corporate finance executives can create reliable models on projected financial results once we have obtained reliable and detailed historical data from companies.

Simultaneously, a massive effort needs to get underway to open all restricted areas with hydrocarbon potential, while we also shore up productive capacity to produce, transport and refine oil at every step along the complex food chain. We need to start removing all the bottlenecks that are squeezing today's current oil output and ensure that we do not worsen shrinking supply by collapsing our infrastructure that makes this supply usable. These badly needed sources of new supply do not end our pending problem, but they become bridges to buy more time.

At the same time, it is crucial that oil and gas becomes used in the most energy efficient ways. On the conservation front, there are some key changes that can be effected to really make a difference within a workable timeframe. But, the solutions turn out to be very different from the list most environmentalists now tout. Most of the currently suggested conservation ideas are either trivial in their impact, take decades to implement, or both. The concept of

continued on p43...

Nuclear – jury still out?

Mojgan Djamarani *looks at the role that nuclear power could play in the future energy balance, assessing the varying cost implications of nuclear versus other forms of electricity generation.*

According to the US Department of Energy's Energy Information Agency (EIA) *International Energy Outlook (IEO) 2004* report, world net electricity consumption is expected to nearly double in the next two decades. Total demand for electricity is expected to increase, on average, by 2.3%/y. Fossil fuels are expected to dominate the energy balance, particularly natural gas, whose use in electricity generation is expected to double by 2025. Coal is projected to retain the largest market share of electricity generation. Largely as a result of the projected increase in fossil fuel consumption in the developing countries, IEO expects global carbon dioxide (CO_2) emissions to grow from 23.9bn tonnes in 2001 to 27.7bn tonnes in 2010 and 37.1bn tonnes in 2025, with emissions from natural gas forecast to rise to 24%.

The recent hike in natural gas prices and growing international concern over greenhouse gas (GHG) emissions has led to a reconsideration of the role of nuclear power in the energy balance. Not only is the construction of new nuclear generating plants currently on the government agenda in the UK and US, but also in a number of European countries that had previously ruled out the use of this form of electricity generation – such as Italy and Poland. At the end of 1999, there were 433 nuclear power plants (NPPs), totalling 349 GW, in operation around the world, meeting 16% of world electricity demand in 2001. A further 37 units (31 GW) were under construction.

Nuclear energy is the only source of electricity that does not produce any significant carbon emissions and has the capability to provide base load power to replace large gas- and coal-fired power plants. According to the OECD's Nuclear Energy Agency, emissions from the full energy chain of nuclear power amount to only 2.5–5.7 grammes of GHG/kWh (grammes of carbon-equivalent) of electricity produced compared to 105–366 grammes of GHG/kWh for the fossil fuel chain and 2.5–7.6 grammes of GHG/kWh for the renewable energy chain. The energy chain takes into account the complete lifecycle of the plant, including construction, which is why even renewable energy carries a non-zero GHG/kwh.

Table 1 summarises the factors that need to be taken into account by policy makers when considering nuclear power as an option. These factors are discussed in this article. However, one of the most important factors, perhaps the most important, is the politics of nuclear power, both domestic as well as geopolitical, together with public opinion (issues that are not addressed here).

Nuclear power plant construction

In the 1990s, no new NPPs were built in either North America or Western Europe; only in East Asia did it expand. In 2000, six new NPPs, with a total capacity of 3,056 MW, were connected to the grid – three in India and one each in Pakistan, Brazil and the Czech Republic. If this trend were to continue as projected by *IEO 2004*, nuclear's share of world electricity would decline to 12% by 2025. However, there is growing optimism by the International Atomic Energy Agency (IAEA) and the IEA that as a result of the entry into force of the Kyoto protocol and the plans and actions of a number of (signatory) countries, based on the most conservative assumptions, global nuclear capacity will rise 22% to reach 427 GW by 2020.

In the opinion of Hans-Holger Rogner and Alan McDonald of the IAEA, NPPs are likely to be more attractive to government investors than for private investors who need a rapid return on their investments and receive no financial benefit from nuclear power's low GHG emissions or contribution to energy security. Therefore, this would make them less attractive in the slower growth, deregulated markets in the West. Current expansion and growth prospects are centred in Asia – 19 of 32 reactors under construction, they report, are located in China, India, Japan, South and North Korea, while 19 of the last 28 reactors to be connected to the grid are located in the Far East.

Continuous improvements

The safety, operational and economic performance of NPPs has improved over the last decade. By 2003 the utilisation of generating capacity of NPPs had increased from 71% in the 1990s to 81%. Those NPPs that have had their capital investment depreciated or written off have become some of the least expensive power plants to operate. According to figures from the US Utility Data Institute, production costs from US NPPs fell below coal-, oil- and gas-fired plants in 1999. They averaged 1.83 c/kWh compared to 2.07 c/kWh for coal, 3.18 c/kWh for oil and 3.52 c/kWh for gas fired plants.

In 2004, the estimated average capacity factor – a measure of efficiency – for the 103 US NPPs was, according to the US Nuclear Energy Institute, 90.6%. Similarly, in the UK NPPs in 2004 generated a record high of 788.5bn kWh of electricity. The low operating cost of NPPs has not been lost on the utilities sector. In the US, by the end of 2004, 30 extensions of NPP licences of 20 years

Factors favouring fossil fuels	Factors favouring nuclear energy
Security of hydrocarbon supply	Lack of hydrocarbon security of supply
Access to low cost fossil fuels	Rising prices of hydrocarbons
	Social, health and environmental costs
	Lower discount rates
	Volatility of fuel prices
	High carbon taxes
	Carbon dioxide (CO_2) costs
	Shorter and cheaper construction costs and standardisation

Table 1: Factors to be taken into account by policy makers when considering nuclear power as an option

each had been approved and more than a dozen sold to private and foreign investors. However, with the exception of Finland (with its Olkiluoto-3 facility) and France, no new NPPs are planned in Europe or North America.

In the fossil fuel sector, standardisation and cost reduction improvements have already been largely achieved, while in the nuclear industry there is still a lot of room for technological and design innovations. A University of Chicago study in 2004 concluded that nuclear power could become cost competitive with coal and gas after the first new plants were built. These first few plants would incur the usual first-of-a kind engineering costs and would have to pay a 3% premium for financing. Recent standardised NPPs with multiple units at the same site, such as the recently commissioned 1,356-MW Advanced BWRs (boiling water reactor) units 6 (1996) and 7 (1997) in Japan and the 1,000-MW standard PWR (pressurised water reactor) Ulchin units 3 and 4 in South Korea were built in less than five years and at reduced capital costs. The French European PWR (EPR; European pressurised water reactor) series is estimated to achieve a saving of 20% in capital costs and reductions in operating costs.

A UK Royal Academy of Engineering report in 2004 looked at electricity generation costs from new plant in the UK, factoring in the cost of stand-by capacity for wind as well as carbon values up to £30/tCO_2 (£110/tCarbon) for coal and gas. Wind power was shown to be twice as expensive as nuclear. Without the carbon increment, coal, nuclear and gas CCGT (combined cycle gas turbine) power generation ranged from 2.2–2.6 p/kWh and coal gasification IGCC (integrated gasification combined cycle) was 3.2 p/kWh (all base load plant). Adding the carbon value took coal close to onshore wind, with back-up at 5.4 p/kWh, while nuclear (based on a conservative £1,150/kWh plant + decommissioning) remained at 2.3 p/kWh.

Social, health and environmental considerations

The management and disposal of spent fuel still remains a challenge for the nuclear sector. Although the nuclear industry is unique in that it is the only energy producing sector that takes full financial and operational responsibility for the disposal of its waste, it has a long way to go to overcome public suspicion.

Two important facts to remember, according to Dr Mohammed El Baradei, IAEA Director General, speaking at a recent international conference on 'Nuclear Power for the 21st Century', are:

- The 12,000 tonnes of spent nuclear fuel produced globally each year is relatively small compared to the 25bn tonnes of carbon waste released directly into the atmosphere from fossil fuel generators.
- Technological difficulties regarding spent fuel disposal or reprocessing have already been resolved but have not yet been demonstrated. Finland is to become the first country to build a final geological repository for spent fuel near its Olkiluoto NPP. Construction is to begin in 2011 and is slated to complete by 2020. Sweden hopes to follow Finland and make a decision by 2007 on one of two candidate sites. The industry hopes that this will go a long way to reassure the public of the safety of the nuclear power.

In the past, the virtual absence of any cost measurements of the negative social and health effects of the burning of fossil fuels, as well as penalties on GHG emissions, has meant that nuclear's advantages have had no tangible economic value. The future competitiveness of the industry depends to a large extent on the additional costs that may be imposed on the fossil fuel generating plants to meet targets for reducing sulphur dioxide (SO_2) and GHG emissions. However, it could also easily lose its economic advantage if, in response to strong public sentiments, new and more stringent safety regulations, or lower limits on radioactive emissions by NPPs, and so forth were imposed.

A study launched by the European Commission in 1991 in collaboration with the US DOE (Department of Energy) and published in 2000 (refer to number 3 in **Figure 1**), looking at the external costs of the various fuel cycles, shows that in clear cash terms nuclear energy incurs about one-tenth of the costs of coal. The external costs are defined as those actually incurred in relation to health and the environment and that are quantifiable but not built into the cost of electricity.

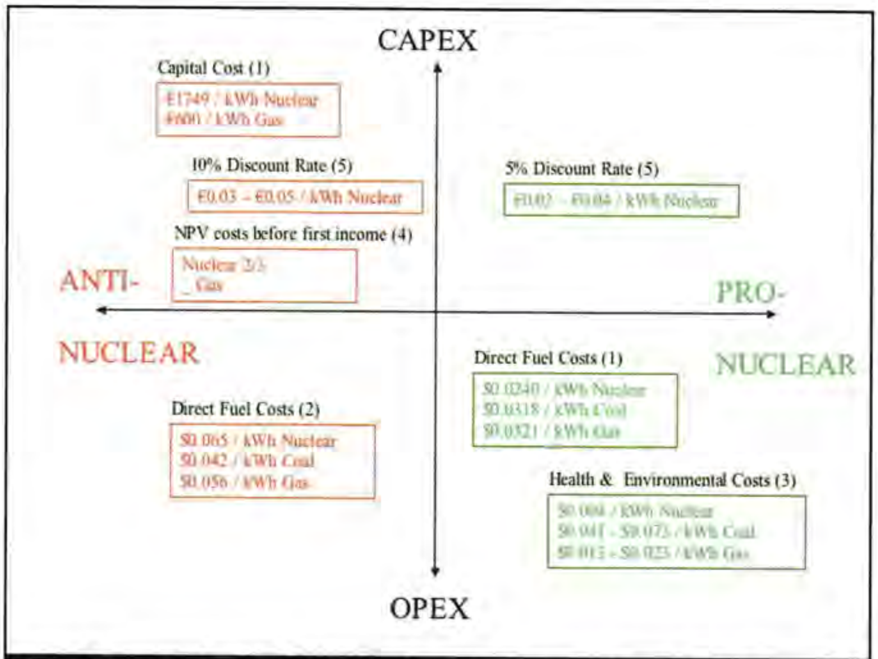


Figure 1: The capital costs of nuclear (numbers in brackets are referred to in text)

General economic forecasts

The relative economics of investing in nuclear power are highly sensitive to one's view of future interest rates, which, in turn, are related to expectations for future economic growth.

A 1998 OECD comparative study (refer to number 5 in **Figure 1**) showed that at a 5% discount rate, in seven out of 13 countries considering nuclear energy it would be the preferred choice for new base load capacity commissioned by 2010. At a 5% discount, nuclear was cheaper than coal in seven out of 10 countries and cheaper than gas in all but one country – the US. [In 1998, US gas costs were approximately one-third of current levels – Ed.] At a 10% discount rate, nuclear becomes more expensive (except in Japan and the Netherlands), with capital accounting for 70% of power costs instead of the 50% it is with a 5% discount rate. However, even at 10% it proved cheaper than coal in seven out of 10 countries and cheaper than gas in eight out of 10.

Studies with different conclusions

A major attraction of nuclear power has always been its low fuel costs. In the 1950s it was even thought that the electricity would be too cheap to even bother with metering. Even though two-thirds of the cost is due to enrichment and fabrication of uranium, the total fuel costs of an NPP are equal to 33% those of coal and between 20% and 25% those of gas in CCGTs in the OECD.

A detailed study of energy economics in Finland (refer to number 1 in **Figure 1**) published in mid-2000 shows that nuclear energy would be the least-cost option for new generating capacity. Nuclear has a higher capital cost than other fuels – up to three times the cost of a gas plant – but its fuel costs are much lower, while at capacity factors above 64% it becomes the cheapest option. The April 2001 figures – assuming 90% capacity factor, 5% interest rate and 40-year plant life – are shown in **Figure 1**. The study also showed that doubling of fuel prices would increase electricity costs for nuclear by 9%, for coal by 31% and for gas by 66%. This is why the volatility of fossil fuel prices makes nuclear power more attractive.

According to Pietro Nivola of the Brookings Institution (refer to number 4 in **Figure 1**), arguing against nuclear power, the capital intensity of NPPs means that two-thirds or more of their costs, when measured on a present value basis, may be incurred upfront before they go online compared to only one-quarter for typical gas-fired plants. This explains why CCGTs have supplied almost all of the total new added capacity in recent times to carry peak loads. Base loads are carried by coal-fired plants, which, although they have capital costs twice those of CCGTs, even with clean air technologies, are still cheaper than nuclear.

According to a study carried out by the Massachusetts Institute of Technology (MIT) (refer to number 2 in **Figure 1**), at an average of 6.5 c/kWh, the fully built up cost of nuclear plants exceeds that of a pulverised coal-fired plant (4.2 c/kWh) and that of a CCGT even at a high gas price (5.6 c/kWh). Even if the exceptionally long construction time of a NPP was reduced to between four and five years, and its high cost reduced by a quarter, the MIT study concludes that coal would still be cheaper and that the NPP would just about match the price performance of a CCGT using high cost gas. High natural gas prices, it says, would eventually lead investors to switch to coal rather than to nuclear.

On the whole, in countries with limited domestic fossil fuel supplies – such as France, Japan, South Korea and Finland – and where security of energy supply is given greater importance, nuclear power comes out more favourably.

In the UK, the impending dependence on gas imports, becoming a net importer in 2006 and the decommissioning of 11 NPPs by 2023 with no current plans for their replacements, has raised the issue of security of supply. However, the current debate on the role of nuclear in the energy mix is being sidetracked by the poor record of the industry and the poor financial performance of British Energy, which had to be bailed out by the government by so much that it has been reclassified as part of the public sector for the sake of national accounts.

According to Tony Grayling of the Institute for Public Policy Research (IPPR), the new generation of nuclear technology is not relevant to meeting UK's Kyoto commitments, or even the UK government's own agenda of reducing carbon emissions by 60% by 2050. Even in the longer term, he thinks, there is a big question mark over nuclear's viability. Government assessment of different ways of generating electricity, he says, shows nuclear to be most expensive.

Instead, the UK is increasingly going for wind energy. It is the country's fastest growing energy sector, which, although currently more expensive than coal and gas, Grayling believes could soon become competitive. Wind power, he says, promises the security of supply that NPPs, with their long and unexpected periods off line, do not. Furthermore, it does not compromise the country's national security.

By 2010, some 9,000 MW of new wind power is planned to be installed in the UK. However, in Germany, which has the largest number of wind farms in the world, a recent report by the government's Energy Agency says that wind farms are an expensive way of reducing GHGs, at a cost of between £28 and £53/t of CO_2 saved. Meanwhile, a National Audit Office assessment in the UK said, last February that wind was the most expensive way to fund carbon emissions reductions at a cost of between £70 and £140/t of CO_2 saved. This, according to Malcolm Grimston of Chatham House, coupled with the intermittent nature of wind, makes nuclear an essential part of any energy mix. However, given that in a competitive market its high costs and long lead times put it at a disadvantage, the government has to find a way to renew its powers to intervene in a liberalised market in order to lure investors.

...continued from p40

energy conservation needs to change from 'this would be a nice thing to do for a cleaner environment' into 'energy conservation is now a necessity, it is important to make changes that really save significant amounts of energy in a realistic timeframe'.

One major conservation effort would be to eliminate the long haul of all goods by trucks and replace this by using trains. This seemingly small change could have an energy efficiency impact of five to ten-fold.

Since oil use is 70% transportation driven, this is the prime efficiency battlefront. Over the course of five to seven years, a great chunk of the global workforce could learn how to work closer to home and not even change jobs. The Internet, e-mail and video-conferencing has created an ability to let people actually work very close to (or at) home and be far more efficient than commuting for hours each day.

The world can also make some profound changes in our agriculture system. A high percentage of the food we eat comes from countries half way across the globe. The energy consumed to send Chilean blueberries to Maine, New Zealand apples to England, or bottled Fiji water to Houston, is a luxury that we can all easily relinquish. A return to 'Victoria Gardens' in the term of locally-based organic farming can make a big difference in how we use scarce and expensive energy.

From the agricultural front can also come some of the new energy sources to begin reducing motor gasoline and diesel fuel use. The world of biofuels has great promise.

A new dawn?

If the world awakes to the reality and urgency of peak oil, *Twilight in the Desert* can turn into a new dawn.

But, if we ignore this looming problem for a few more years – and my worst worries are proved right – the hole we dig might become the twilight of the way we now live and turn the world into a far darker place than anyone would like to contemplate.

Twilight in the Desert: The Coming Saudi Oil Shock and the World Economy, by Matthew R Simmons, is available from John Wiley & Sons, The Atrium, Southern Gate, Chichester, West Sussex PO19 8SQ, UK. t: +44 (0)1243 843222; **www.wiley.com** ISBN 047173876X, 422 pages, priced £15.99 (hardback).

Oil price impact on UKCS

In the past 12 months, the price of oil has risen considerably. This increase can be directly related to demand, political instability, refinery capacity, natural events, weather and lack of investment. Commentators suggest that demand will continue to grow massively over the next 30 years – but what impact will this have on the economy? The 7th Logic conference – for the first time jointly organised by Logical Advantage Ltd and the Energy Institute – addressed this issue, assessing the impact of the current high oil price on UKCS business.* Kim Jackson *reports.*

With scene-setting keynote speeches from both government and industry, the conference speakers discussed just how well the UKCS (UK Continental Shelf) is positioned in a number of key areas, including availability of infrastructure, peak oil and the appetite for exploration in the UKCS, maximising economic recovery from mature fields, and investment strategies of all UKCS businesses.

Working breakfast

Audience participation was key throughout the event, with delegates given the opportunity to voice their opinions, on the most important issues facing today's oil and gas industry, in a series of panel discussions and via a hand-held voting system. In fact, the voting process kicked off the event, as delegates were called for their opinions on a number of questions posed over breakfast. Among the issues addressed was climate change – with 55% of the delegates believing this was 'happening and of considerable concern'. A further 18% felt that this issue was 'not getting nearly enough attention', while 14% believed it to be 'the most serious challenge facing us all'. Some 7% felt that it was 'happening, but of minor concern', while the remaining 6% felt that the 'jury was still out' or that it wasn't a subject worth debating.

Delegates were invited to voice their opinions throughout the day via a hand-held voting system, beginning with the breakfast briefing

When asked about the impact of the sustained high oil price on the UK upstream industry, 53% felt that it had been 'really positive', 40% 'slightly positive' and just 7% voted 'neutral'. The verdict was a little more wide-ranging when asked about the impact of a sustained high oil price on each delegate's own company. Here, 36% felt the impact had been 'really positive', 30% voted 'slightly positive', 16% 'neutral', 16% 'slightly negative' and 2% 'really negative'.

The final question posed during breakfast asked delegates to look in to their crystal balls and predict what the oil price would be in a year's time. The audience was fairly split on this, with 49% forecasting a price of 'between \$51/b and \$65/b' and 47% envisioning a price of 'between \$36/b and \$50/b'. The remaining 4% was divided between '<\$20/b' and 'between \$21/b and \$35/b'.

The result of the final vote was somewhat strengthened by Paul Horsnell, Head of Energy Research, Barclays Capital, the investment banking division of Barclays Bank, who presented an in-depth oil market outlook before the main proceedings began, chaired by Clive Fowler, Logical Advantage. Horsnell's speech suggested that the market view of long-term price had 'moved up' – no longer was the industry looking at \$20/b oil, the signal now was more for a per barrel price of \$45–\$50.

He noted the 'gathering story' is Russia, where recent year-on-year growth in output is now decelerating, having stagnated since August 2004 when year-on-year production growth had topped out at 800,000 b/d – a figure that is expected to be negative by the end of the year. Meanwhile, demand is continuing to rise – in particular in countries such as China, which Horsnell saw as a 'big source of swing'.

Horsnell also commented on the skills shortage being faced by the oil and gas industry, stating that while there were many talented personnel in their late 40s and 50s, and also an influx of those in their 20s, there was a definite lack of skilled labour aged in between.

Looking downstream, Horsnell commented that spare sustainable capacity had 'shrunk to low levels', a situation that 'has accelerated over the last two years, with demand growth far outstripping refining capacity growth.' Indeed, 'at seasonal highs of demand, spare capacity has completely gone', he noted. Quality differentials had also widened considerably over the past five years – from about \$1/b to \$14/b for Saudi crude exports into Asia, relative to a Dubai/Oman average.

In Horsnell's closing comments, he said that the industry could 'look towards more tightness and more volatility'. There were 'major changes' taking place in 'terms of dynamics', many of the long-term producers 'were not viable at <\$40/b' and that \$45–\$50/b provided a 'nice, sustainable level'.

Issues of the day

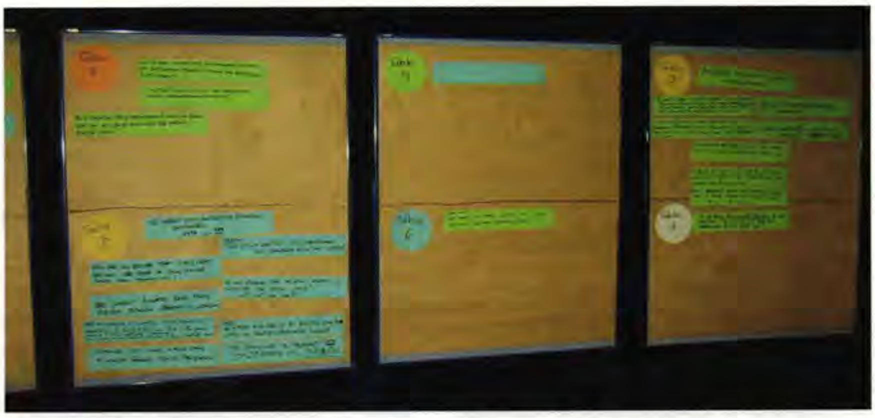
The first of the main morning keynote presentations was given by Sir Robert Smith, MP for West Aberdeenshire and Kincardine, and Vice Chairman of the All-Party Group for the UK Offshore Oil and Gas Industry, who echoed many of Horsnell's observations. He stressed in particular the need for continued and improved dialogue between government and industry, and also between them and the consumer – who needed to 'see beyond taxes on road fuels' and 'understand the wider political context' and the 'benefits that the industry brings to the economy'. Sir Robert also noted industry's need to 'be more imaginative' in how it attracted people to the sector and in how it retained skilled personnel, calling for more interaction between industry and schools, including primary level education.

He said that industry should play to its strengths of a stable political and fiscal regime for investors, coupled with a not overly burdensome regulatory approach, stating that 'the government only gets tax if industry gets the reserves out of the ground'.

Michel Contie, Managing Director, Total E&P UK was next up to the podium. He began by reviewing historic crude prices, noting that despite recent increases, in real terms the price has not risen to the levels seen in the 1975–1985 period. He went on to query why, if consumption has been steadily rising despite fluctuations in the oil price, had planners not forecast this increased demand leading to a shortage in production capacity in the future? He stated that the changes in the oil price over the past 12 months had been largely driven by the increasing demand in the developing economies of the Asia-Pacific region, in particular China and India. Tightness in supply had been the result of maturing oil fields.

Contie noted that today, just 24 companies produce close to 66% of world oil production and, among these, only seven are international oil companies (IOCs) holding a 17% market share. He also noted that oil and gas would continue to have a key role to play in the future

Delegates during the morning session



During lunch, delegates were invited to post up questions for the panel Q&A session at the end of the day

energy mix, accounting for 37% and 48% respectively by 2020 (32% and 42% in 2004), with renewables only expected to account for 5% (2% in 2004).

Looking specifically at the UKCS, Contie stated it was a situation where the 'glass was half full' – some 28bn boe had been produced to date, with a further 28bn yet to be produced. He anticipated a continued increase in exploration and appraisal (E&A) activity, despite rising costs, forecasting the drilling of over 70 E&A wells in 2005 (compared to 63 in 2004).

He concluded by stating that high oil prices provided the 'opportunity to secure the future' of the UKCS, but stressed the industry had to be' careful that the high oil price situation didn't hide inefficiencies that needed to be addressed'. Fiscal stability and predictability were 'key components' and 'strong leadership was required'. Lastly, he called on consumers and government to 'play their part by adopting energy conservation measures'.

Taking a break

During the refreshment break, delegates had the opportunity to network, discuss the topics so far debated, and to visit the stands of two Aberdeen-based, web-enabled procurement solution providers – ENERDOX (**www.enerdox.co.uk**) and First Point Assessment (**www.fpi-oil.com**).

ENERDOX Ltd. is the European provider operation of EOS Technologies' Digital Document Exchange. Claimed to be capable of cost-effectively connecting to any system(s) an organisation may be using at present or wish to implement in the future (such as enterprise resource planning (ERP) solutions, value added networks (VAN), electronic data interchange (EDI) solutions and catalogue-based exchanges), the ENERDOX document exchange currently has over 3,000 members worldwide, and has recently 'gone live' in the UK.

First Point Assessment (FPAL) is an industry-steered oil and gas supply chain database that is used by purchasers to source detailed information on current and potential suppliers when awarding contracts or purchase orders.

Government goals

Joan MacNaughton, Director General, DTI Energy Group, began her presentation by outlining the four main goals of the UK government's Energy White Paper, published in February 2003.

Left to right: Clive Fowler, Logical Advantage and conference chair; Michel Contie, Managing Director, Total E&P UK; Joan MacNaughton, Director General, DTI Energy Group; Sir Robert Smith, MP for West Aberdeenshire and Kincardine and Vice Chairman of the All-Party Group for the UK Offshore Oil & Gas Industry

These were:

- Getting on a path to cut the UK's carbon dioxide emissions by 60% by 2050
- Maintaining the reliability of energy supplies
- Promoting competitive markets in the UK and beyond
- Ensuring that every home is adequately and affordable heated.

She pointed out that the UK was the first of the world's largest economies to set out such a comprehensive strategic energy policy and stressed the importance of tackling and delivering each of the four goals 'together' in order to 'maintain balanced decision making'. Focusing attention on the importance of the UK oil and gas sector to the economy, she stressed the need to inform the world that the UKCS was 'far from a sunset industry', with some 28bn boe yet to produce. Key to 'maximising recoverable reserves' was 'close working between government and industry' to 'incentivise investment' and MacNaughton went on to outline important recent initiatives such as the development of 'Promote' and 'Frontier' licences, the Infrastructure Code, the Fallow Field and Brown Field programmes, Pilot and the concept of Stewardship. Echoing the thoughts of the other speakers, she also noted that 'skills are a priority' as well as 'supply chain issues'.

This was followed by a panel Q&A and lunch, during which delegates weren't allowed to sit on their laurels! They were asked to write up questions – including some with answer options on which votes could be cast – that would be put to the panel at the end of the afternoon's proceedings.

Shaping the future

Johan Bakker, Vice President, Halliburton Energy Group, Europe Eurasia Region, kicked off the afternoon session with his presentation entitled 'High oil price – shaping the future', looking at how $50/b oil impacted the service sector. He pointed out that, while there were a number of factors that the industry can't control – such as the economy, weather, demand for hydrocarbons, the price of oil and gas, stock market influences and geopolitics – there were a number that could be controlled or, at least, influenced. These included 'stewardship of UK reserves for sustainability; the commercial models that oil service companies, oil companies and the government apply to achieve the industry's objectives; implementation of the right technologies; investment in capital and human resources; and the way in which the industry as a whole and government work together to make efficient use of resources and manage risk'. However, he warned that 'higher oil prices may distract us from these challenges'.

Bakker went on to state that the 'UKCS must still compete for international capex... we need to invest in production, not just harvest... increasing rig and service rates may delay activity... infrastructure is at risk from high maintenance costs... supply chain management may be in the way', with 'short term contracts based on price not value-giving', which, in turn, 'leads to an impact on R&D spend'. He also noted the need for 'collaborative business models and equitable risk', and called for 'funding of technology development and uptake'.

Bakker couldn't stress enough the importance of technology and innovation that could help improve financial leverage of projects by lowering costs. He noted that while the oil companies had consistently reduced their level of R&D spend, the service sector had increased funding levels. 'It is important that the service industry has a sustained period in which it can invest in R&D', he said.

What to invest in?

Delegates were also invited during the day to participate in interactive '10-minute pitch' sessions, where they were asked to imagine that they had £10mn to invest in one of five different energy related sectors – Promote, New Entrants, Big Oil, SME, Service. The objective for the delegates was to maximise their return on investment under two case scenarios – in the short to medium term (0–5 years) and in the medium to long term (6–ten years).

The Promote pitch came from Steve Kew at Excite Energy Resources, who called for the delegates to invest in licence 9/3b – a very large pool of some 650mn barrels of proved, but as yet undeveloped, 17° API oil reserves. Recoverable reserves were put in the region of 75mn barrels, with a downside of 35mn barrels and upside of 150+mn. Four wells had been drilled on the block, three proving hydrocarbons. He marketed the investment as 'low risk' as all the ground work had been done, with 'high multiples of return' – a sure thing!

Nick Williamson, a Partner at Ashurst, took the podium on behalf of Big Oil, who assured the delegates that Big Oil was a 'safe bet' as it would be a case of 'not putting all your eggs in one basket'. He stressed the 'high levels of experience and expertise' that would be brought to the investment, and the 'proven track record'. Big Oil represented a 'low risk' opportunity, with a 'stable and healthy return'.

Next up was the New Entrant, represented by Logical Advantage's Chris Freeman, who was seeking funding to develop a new discovery and for new acquisitions. He pointed to the flexible and creative nature of the company and the good relationships that had been developed via 'active portfolio management' in which 'shareholder value is key'. All of this, he claimed, would provide 'good returns to stakeholders – especially if we sell up afterwards!'

Barry Hood of NOVA asked for delegates to invest in a porfolio of SMEs, which 'represent 99% of all enterprises in the European Union, employing 65mn people (some two-thirds of the total working population). He reported that 50% of SMEs are less than a year old, and they are 'major innovators and drivers of growth'. Hood suggested that the £10mn be invested in 10 to 12 UK trusts that would offer a mix of short, medium and long-term opportunities with low, medium and high levels of risk.

Colin Welsh of Simmonds & Company International presented the final case – on behalf of the Service industry, a key sector in which some $3tn was forecast to be spent on oil industry investment between 2003 and 2030. He pointed out that much of the global infrastructure required investment, development opportunities in countries such as Russia and China continued to grow, more rigs, people and investment would be needed – and, basically, the service sector (and its investors) was well placed to reap the rewards!

After a 'Blind Date' style review of the five pitches, delegates placed their votes. And the overwhelming winner was... the Service sector, which secured the £10mn in both investment scenarios – accounting for 50% of the vote under the short to medium-term return case, and 31% in the medium to long-term case. However, it was noted that there was an inevitable element of bias in the voting process as some 20% of the audience was from the service company sector!

The Promote pitch secured 18% of the vote in the short to medium term and 21% in the medium to long term; the other percentages were Big Oil 8% and 21% respectively, New Entrant 13% and 6%, SME 11% and 21%.

The 'prize' – an IOU for £10mn – was to be 'put in the post'!

Final round-up

Graeme Sheils, Senior Assurance Advisory Partner at Deloitte, then went on to provide a comprehensive round-up of the day's proceedings. He stated that the 'world has changed' and that it seemed 'likely that $50/b oil was here to stay just now'. Demand was, and would continue, to rise, while supply would continue to be constrained. There was also a widely acknowledged need for 'partnering across stakeholders', not only through government initiatives such as Pilot, but also between the oil companies and the service sector/supply chain. Sheils went on to note that there were a 'number of priorities' for the UKCS to address – including the issue of security of supply and placing an emphasis on the region's fiscal stability and developing initiatives to encourage this in order to secure ongoing investment. He also pointed out that the skills shortage had been highlighted throughout the day and stressed the need to build up a skills base on which the future of the UKCS and the UK oil and gas industry could stand.

Sheils said he was 'somewhat surprised' that the topic of decommissioning had not been raised during the day's proceedings and asked: 'Does this mean we are looking at a sunrise or are we just shying away from the issue?' He stressed that solutions needed to be sought and ways of funding decommissioning addressed. He also noted the importance of continued investment in R&D to fund new technologies and innovations.

According to Sheils, there was still a considerable 'UKCS prize' to unlock – to the tune of $560bn at $40/b oil.

The day closed with a panel Q&A session, the final one of which asked: 'What is the most important issue for industry to address in order to secure the long-term future of the UKCS?' The answers were – developing new technologies 44%, skills shortage 26%, infrastructure 15% and supply chain 15%... all in all, a pretty good reflection of the issues addressed during what was a very informative, interesting and lively day's debate.

** Held at the Aberdeen Exhibition and Conference Centre on 9 June 2005. Event sponsored by Halliburton; lunch sponsored by Barclays.*

LETTER TO THE EDITOR

Dear Sir

Your editorial in the June 2005 issue regarding the time to consider nuclear is excellent.

You are, of course, aware that the government has authorised the import of increasing quantities of LNG to the UK whilst at the same time expecting CO_2 (carbon dioxide) and greenhouse gas emissions to be reduced.

The liquefaction of natural gas and its transportation to the UK releases very considerable quantities of CO_2 directly into the atmosphere, mostly outside the UK. Heat will also be needed for vapourising the liquid and increasing its temperature to make it suitable for the gas distribution network.

Important questions, therefore, need to be addressed. For example, will the UK have this produced CO_2 added to the annual emissions that the UK government is responsible for or will it be charged against foreign countries of origin where the LNG was liquefied?

The major importers of LNG should be able to advise you of the massive amounts of CO_2 generated in the production and transport of LNG.

In other words, is it ethical to import LNG without crediting the CO_2 emitted in its production and transportation to the importing country – ie to the UK?

Peter Kemp FEI

...continued from p2

are infant industries with economics still largely dependent on subsidy or extraordinarily high carbon values. Nuclear is another way out of the box, but still needs to find satisfactory solutions to, and public acceptance about, safety and waste disposal concerns.

If, as is overwhelmingly likely, coal and hydrocarbons dominate future energy supplies, then the imperative is to use them as efficiently as possible. This is the strategy that everyone agrees on and everyone finds very boring. Yet it works. It is the one area where clear government regulation can provide a level playing field and business can deliver the required results, while its absence could lead to disaster.

In the US, the story of the CAFE (corporate average fuel efficiency) standards provide a modern parable. Introduced after the oil crises of the 1970s, the CAFE regulations were highly successful in driving up vehicle fuel efficiency. Detroit, however, successfully lobbied the Republicans that this was not the Amercian way and succeeded in getting the standards frozen (rather than tightened further) and gaining numerous exemptions.

This, in turn, allowed Detroit to develop and market the SUV (sports utility vehicle). As this was essentially an upholstered small truck they were able to exploit the undemanding fuel standards to make a low-cost product that was very profitable (up to six times as profitable as ordinary cars). Recent Republican administrations added further tax breaks to keep sales rolling, despite dramatic inroads being made by Japanese and European manufacturers offering more efficient and more sophisticated vehicles. (The Japanese and Europeans having been driven to efficiency by high fuel taxation – one alternative to CAFE standards.)

Then came this year's high oil prices and consequent high gasoline prices. US SUV sales are now falling rapidly. General Motors' debt now has junk bond status and the company is to reduce production by 20% to try to survive and regain profitability.

Unfortunately, General Motors may be a good proxy for the whole US energy scene. The US could use high taxes to drive energy efficiency – like the Europeans and Japanese – or it could use mandatory and tightening standards like CAFE. But, if it doesn't, what has proved bad for General Motors could prove bad for the US economy.

Chris Skrebowski

Improving awareness of the petrochemical industry

A number of VOSA (Vehicle and Operator Services Agency) officials were among the latest 12 delegates, also including employees from BP Oil and Heil Trailers, to recently 'graduate' from the all-encompassing SOE & Energy Institute-endorsed TransTrain petrochemical safety and procedures course, held at the BP Oil Terminal in Kingsbury, West Midlands.

VOSA provides a range of licensing, testing and enforcement services with the aim of improving the roadworthiness standards of vehicles, ensuring the compliance of operators and drivers with road traffic legislation and supporting independent traffic commissioners.

John West, Senior Vehicle Examiner, VOSA, felt that the TransTrain course was of great benefit, significantly improving his awareness of the petrochemical industry: 'We at VOSA cover a wide range of vehicles. This TransTrain course covers one sector and covers it well. Not only does the course give a general overview of the entire petrochemical industry, which brushed up on my existing knowledge, but it also presents detailed current standards. The knowledge I refreshed and gained will be passed on to my team and will prove to be of great importance. For example, when a petrochemical or other hazardous vehicle is examined at one of our road-side enforcement checks, our enhanced industry and vehicle safety awareness will help us identify more easily the items to look for and why.'

The three-day TransTrain courses, which are held throughout the year and given by an industry specialist of 30 years, cover all aspects of safety, maintenance, testing and general procedures concerning petroleum road tankers, ensuring that operatives at every level of involvement with petrochemicals do not put themselves, their company or others at risk.

The Module A (one day) course has been designed for any employees involved in the handling, sales administration, manufacture, repair, design, inspection and testing of petrochemical tankers. It provides an introduction to petroleum industry health and safety requirements, including understanding the product and associated hazards. The three-day Module B course is aimed at vehicle technicians likely to be involved in the full range of tasks relating to the testing, inspection, maintenance and repair of petroleum road tankers. It is a course written by the industry for the industry, which takes an experienced mechanic/technician to a high level of competence when working with petroleum vehicles. The course includes product knowledge and associated hazards, oil company terminal procedures, product loading precautions, workshop standards and procedures, applicable legislation, inspection, testing and certification requirements.

t: +44 (0)1326 569267
f: +44 (0)1326 565847
e: jane@transtrain.co.uk

New high-capacity screw pump unveiled

DESMI's range of submersible vertical screw pumps for the maritime and oil sectors has been complemented with a new mid-size pump – the DOP-200 (Desmi Offloading Pump). The new pump can move mixtures of oil, oil and water, or just water, while still generating up to 188 psi in the discharge hose. When pumping oil and water mixtures, the positive displacement design means that the oil is not emulsified.

The high pressure is achieved due to special discs that fit into the screw as it rotates, rather like spokes in a wheel, explains the company. In addition, a special knife is fitted to the leading edge of the screw to cut up rope, weed and other contamination.

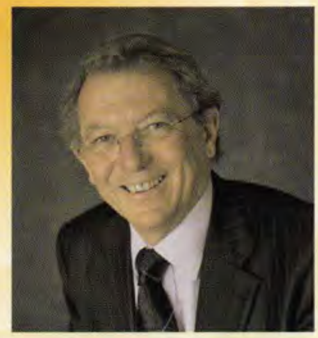
The DOP-200 is also fitted with dual discharge ports, for horizontal and vertical connection of the hose. It has an 8-inch inlet, 4-inch discharge coupling and weighs only 128 lbs. Its' larger brother, the DOP-250, can pump up to 550 gallons per minute, while the smallest pump in the range – the DOP-160 – is capable of pumping 130 gallons per minute.

t: +1 757 857 3169
e: **stewart@ro-cleandesmi.com**

Last chance to book!

energy INSTITUTE

EI Summer Luncheon



Tuesday 12 July 2005, Royal Automobile Club, London
Drinks reception: 12.15, Lunch: 13.00

Guest of Honour and Speaker
***Sir David King*, Chief Scientific Adviser to HM Government and Head of the Office of Science and Technology**

Price: **Members – £80.00 (+ VAT £94.00)**
Non-members – £90.00 (+ VAT £105.75)

The EI Summer Luncheon is now an established date in the Energy Institute's calendar of events.

This event has been designed to provide guests with a fantastic opportunity to network with colleagues drawn from across the UK's energy spectrum.

In addition, the Summer Luncheon has developed a reputation for attracting leading industry figures to provide their analysis and commentary on current market conditions and the 2005 Luncheon is no exception!

To apply for tickets, please complete this form in BLOCK CAPITALS and return it to the address below, together with payment in full.
Arabella Dick, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK.
t: + 44 (0) 20 7467 7106, f: + 44 (0) 20 7580 2230, e: arabella@energyinst.org.uk

Title : ______ Forename(s): ______ Surname: ______

Company/Organisation: ______

Mailing Address: ______

______ Postcode: ______

Country: ______ e: ______

t: ______ f: ______

☐ I wish to order MEMBER rate ______ ticket(s) @ £80.00 each (+ VAT £94.00)
EI Membership No: ______

☐ I wish to order NON-MEMBER rate ______ ticket(s) @ £90.00 each (+ VAT £105.75)

☐ I wish to become an EI member at a cost of £74.00 (included/VAT zero-rated), therefore I am only paying the MEMBER rate Total ______ inc VAT

I will pay the total amount by (please tick appropriate box):

☐ Sterling Cheque or Draft drawn on a bank in the UK
I enclose my remittance, made payable to Energy Institute, for £ ______

☐ Credit Card (Visa, Mastercard, Eurocard, Diners Club, Amex ONLY)

☐ Visa ☐ Mastercard ☐ Eurocard ☐ Diners Club ☐ Amex

Please note that all payments made by credit card will be subject to the following surcharge:
Visa/Mastercard/Eurocard/Diners Club: 2% of the total amount due. American Express: 3% of the total amount due.

Card No: ______

Valid From: ______ Expiry: ______

Credit card holder's name and address: ______

Signature: ______ Date: ______

Photocopies of this form *are* acceptable

For more information and table bookings please contact:
Arabella Dick,
Energy Institute,
61 New Cavendish Street,
London W1G 7AR, UK.
t: +44 (0)20 7467 7106
f: +44 (0)20 7580 2230
e: arabella@energyinst.org.uk

TERMS AND CONDITIONS

When completing and sending the booking form, the purchaser is liable for full payment of the event fee. Full payment must be received before place(s) can be guaranteed. Under UK Excise Regulations delegates from all countries are required to pay VAT on any event taking place in the UK. The Energy Institute. Registered in England No. 1097899. 61 New Cavendish Street, London W1G 7AR, UK.

Ticket price includes pre-luncheon drinks, and 3-course lunch with wine. Cigars and liqueurs are not included.

In the event of cancellation of attendance by ticket purchaser a refund, less 20% administration charge of the total monies due, will be made provided that notice of cancellation is received in writing on or before 13 June 2005. No refunds will be paid, or invoices cancelled after this date.

DATA PROTECTION ACT

The EI will hold your personal data on its computer database. This information may be accessed, retrieved and used by the EI and its associates for normal administrative purposes. If you are based outside the European Economic Area (the 'EEA'), information about you may be transferred outside the EEA. The EI may also periodically send you information on membership, training courses, events, conferences and publications in which you may be interested. If you do not wish to receive such information, please tick this box ☐

The EI would also like to share your personal information with carefully selected third parties in order to provide you with information on other events and benefits that may be of interest to you. Your data may be managed by a third party in the capacity of a list processor only and the data owner will at all times be the EI. If you are happy for your details to be used in this way, please tick this box ☐