Petroleum review

JULY 2004

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- Cash for gas
- Turning gas into liquids

Climate change
- Utilities at frontline of emissions
- Emissions trading – friend or foe?

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

No single letter abbreviations are used.

Abbreviations go together eg. 100mn cf/y = 100 million cubic feet per year.

Front cover: The LNG market is enjoying an unprecedented period of expansion (see p12)

Photo: QatarGas

contents

news

special features

features

regulars

ROUNDUP From the Editor

Better news on several fronts

In June the International Energy Agency (IEA) once again revised its demand estimates upwards, adding 360,000 b/d to give a new 2004 estimate of 2.3mn b/d. Now it is obviously good news that the world economy is recovering strongly, but the unexpected good news is that the oil price, far from spiking up above $40, has continued to ease down to the mid-$30s.

The usual explanations – Opec, speculators, stocks – give some, but not all, the answers to this apparent riddle of strengthening demand but weakening prices.

Opec has just raised its official quota for the 10 members (excluding Iraq) to 25.5mn b/d from July and to 26mn b/d from August. However, as May production by the 10 members was 26.14mn b/d, quotas are hardly constraining production. Virtually all the plausible spare capacity is now in Saudi Arabia and, if the country has – as it claims – moved to producing 9.1mn b/d, there is no sustainable Opec spare capacity left until the next tranche of Saudi capacity – Abu Safah and Qatif – come onstream in October.

Strong demand growth and Middle East uncertainties mean that we are a long way from a reversal of speculator positions and a downward push to prices.

Stocks, however, may provide the most plausible explanation. Recent changes in secondary stocks have been relatively small. So, the true explanation may lie in tertiary stocks – the stocks held by companies in support of day-to-day operations. Confronted with improving markets and daily headlines about Middle East instability, companies have almost certainly elected to fill and keep their tanks full. If, as is likely, there has been a global move to build tertiary stocks this could account for the demand surge that drove prices above $40/b at what would otherwise be a slack time of the year. Barring a Middle East miracle, the extra stocking is unlikely to unwind quickly, but having stocked up the excess demand quickly disappears. So, is demand set to slow a little?

Megaproject review

The *Petroleum Review* database has 19 megaprojects due onstream in 2004. Project slippage appears to have driven most into the third and fourth quarters. So far, only Bayu-Undan (gas liquids) in February, Karachaganak Phase II (gas liquids) and Marlim Sul II (oil), which both came onstream in June, are adding to global supplies. The other 16 will be adding to supplies over the rest of the year. [In next month's issue we will reprint a fully updated and expanded table of oil megaprojects and our first table of gas megaprojects, in addition to more gas coverage postponed due to lack of space in this issue.]

Russian reports

The public announcement by President Putin that he does not wish to see Yukos pushed into bankruptcy was widely taken as a positive sign for both Yukos and investment in Russia. Hopefully this is so. But as so often with Russia, contradictory reports appeared within the day. Similarly, Russian reports of rapid production growth were quickly followed by reports that Russian output might stall at current levels (around 9mn b/d) in 2005. Clearly there is a faction in Russia who would like to cap production as this particular 'kite' is regularly flown. For those who like irony, the news that Opec was asking Russia to expand production to cap prices must have caused a wry smile.

Welcome back

According to a recent presentation and Wood Mackenzie's *Latin America Upstream Insight*, Colombia now offers the most competitive fiscal terms in South America to oil companies wishing to explore and develop. Faced with limited exploration success and declining production (564,000 b/d in 2003 from a peak of 838,000 b/d in 1999), the government decided that although the security situation had improved enormously better terms were needed if it was to attract more investment from the international oil companies.

The Colombians have tackled the problem by removing regulatory powers from Ecopetrol and setting up Agencia Nacional di Hidracarburos (ANH) to administer and regulate the upstream sector, leaving Ecopetrol as a state-owned integrated oil and gas company. In addition, oil company term contracts were modified to allow full depletion of fields, while the tax terms and conditions have been improved, contract terms lengthened and mandatory state participation removed. So far their efforts have been rewarded with the return of ExxonMobil and Shell, and generally greater international oil company interest.

continued on p28...

e-world

BigOil.net and Graydon UK have formed a strategic alliance to introduce Graydon's online database of over 4mn UK companies and businesses via the **www.BigOil.net** web portal. BigOil.net users can now receive all the business information they need in order to set optimum credit limits for new customers. This new gateway will also allow users to obtain credit information on companies in most European countries and major export markets. Credit reports can be obtained instantly using a credit card for payment.

www.energyprojects.co.uk is a new website, developed by the Open University's Energy and Environment Research Unit and funded by the UK DTI, which is designed to transfer UK experience and expertise on the use of renewable energy sources such as wind, solar, hydro and biomass.

The EnergyFiles Oil and Gas Service is a new online information system specialising in providing data and forecasts on global oil and gas. The data is set out in a format that can immediately be used in presentations and for research. Accompanying the exhaustive material in the site itself, a research room offers links to global oil and gas company, government and other sites for further analysis. Visit **www.energyfiles.com** for access to free regional plots and examples. The Energyfiles Oil and Gas Service is a joint venture between Douglas-Westwood and Energyfiles Ltd.

The World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI) recently released a new edition of the international standard used worldwide by businesses to report and set targets for their greenhouse gas emissions (GHGs). The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard, first launched in 2001, has become the most widely used global standard for corporate accounting of greenhouse gas emissions. For more details, visit **www.wbcsd.org**

The UK Health & Safety Executive (HSE) has set up a new area on its website at **www.hse.gov.uk/cdg/** which is devoted to the transport of dangerous goods. It provides access to the new British Carriage of Dangerous Goods Regulations, the authorisations that provide exemptions and HSE's guidance on the use of the new Regulations. It also has some background on the UN system of classification and labelling, details about international regulations, and useful links to other organisations.

In Brief

UK

Four 'Frontier' licence applications *were received under the UK's 22nd Offshore Licensing Round, as well as 42 applications for 'Promote' licences and 30 for traditional licences. A total of 164 seaward blocks were applied for in total, 25 more than the previous round. Some 20 of the 68 companies who applied are potentially new entrants in the North Sea. Meanwhile, some 30 applications were made for onshore licences in the UK's 12th Onshore Licensing Round, more than three times the amount from the previous round.*

The Second Licensing Round for exploration *on the Faroe Shelf will open on 17 August 2004, with applications to be submitted to the Faroese Petroleum Administration by 17 November 2004. Licences are expected to be awarded in January 2005. Details of the round are available from* **www.ofs.fo**

Petro-Canada is proposing to buy *Intrepid Energy North Sea, thereby acquiring a 29.9% interest in the EnCana-operated Buzzard oil field in the UK North Sea, for $840mn (C$1,150mn).*

Eni has signed a sales and purchase *agreement with Canadian Natural Resources International to dispose of a package of mature assets in the UK sector of the North Sea. The divestment comprises interests in the T block area (88.74% in the Toni, Tiffany and Thelma fields) and B block area*

Errata

Volume correction factors

The article on volume correction factors by velocity of sound on pp36–39 of the April issue of *Petroleum Review* unfortunately included some errors. A pdf version of the fully corrected article can be emailed direct to you – please send request to e: **petrev@energyinst.org.uk** – or download the pdf from the *Petroleum Review* homepage via the EI website at **www.energyinst.org.uk**

Front end loading

Please also note that the article on front end loading (FEL) on pp28–30 of the June issue cited an incorrect website address for Strategic Decisions Group (SDG). The correct site address is **www.sdg.com**

NEWS Upstream

ExxonMobil and Apache agreement

ExxonMobil and Apache have announced a programme that is claimed will 'capitalise on the respective strengths and assets of both companies to optimise hydrocarbon exploration and development in the US and Canada'. The agreement provides for transfers and joint venture activity across a broad range of prospective and mature properties in West Texas, Western Canada, onshore Louisiana and the Gulf of Mexico Continental Shelf, and is expected to increase the realised value of the portfolio for both companies.

Apache's participation in the agreement will include a cash payment of $385mn, while ExxonMobil has agreed to transfer its interests in 28 mature producing oil and gas fields in West Texas and New Mexico with current gross production of about 10,000 boe/d and will retain a revenue interest indexed to oil price through 2009. ExxonMobil will also retain a 50% working interest in all properties beneath the currently producing intervals.

In the Western Canadian Province of Alberta, ExxonMobil will farm out its interest in approximately 300,000 acres of undeveloped property interests in mature areas to Apache. Apache will drill and operate more than 250 wells over an initial two-year period with upside for further drilling. ExxonMobil will retain a 37.5% lessor royalty on fee lands and 35% of its working interest on ExxonMobil leasehold as to any production resulting from the drilling programme.

Regarding onshore Louisiana and Gulf of Mexico shelf acreage, the parties jo will explore jointly for deep gas on more than 800,000 acres of high-potential Apache onshore and offshore properties for an initial period of five years, with provisions for extension.

Gas pipeline system proposal for south Vietnam

Thailand's state-owned PTT is understood to have signed a Memorandum of Understanding with Petrovietnam to jointly study the possibility of constructing a natural gas distribution pipeline system in southern Vietnam. The companies plan to set up a joint working group to look into the feasibility of the project, initially focused on 12 industrial zones of Ho Chi Minh City. The study is expected to be completed by 2005. This is reported to be the first time that PTT has ventured outside Thailand to invest in gas distribution pipelines.

Vietnam produced more than 1.6bn cm of gas in 1Q2004, the Nam Con Son Basin off southern Vietnam accounting for some 8mn cm/d (282.4mn cf/d) of production. Most of the Nam Con Son gas is currently used for power generation by state-owned Electricity of Vietnam. However, the government is trying to promote natural gas as a fuel of choice for the industrial sector.

Gas production from the Nam Con Son Basin is expected to increase to 3bn cm/y between 2005 and 2007. Output is expected to rise to 7bn cm/d (676mn cf/d) after 2007, when the basin's Lan Do and Hai Thach gas fields come onstream.

Chinguetti gets development go-ahead

Woodside Petroleum is to proceed with the $600mn development of the Chinguetti oil field offshore Mauritania, following joint venture approval for the project. Oil production from the field is expected to begin by March 2006 at about 75,000 b/d. Proven and probable reserves are put at around 120mn barrels.

Woodside holds a 53.846% operating stake in Chinguetti, with Australian partners Hardman Resources and Roc Oil holding 21.6% and 3.693% respectively. The remainder of the field is held by BG Group, with 11.63%, and Premier Oil with 9.231%.

Chinguetti will be the first production operated by Woodside outside of Australia and will be a major contributor to the company's production and revenue stream. Since Chinguetti was drilled, Woodside has also discovered gas at the Banda field in area A and more oil at Tiof in area B.

The Chinguetti development will include six production wells and four water injection wells for reservoir pressure support, with flowlines to a permanently moored FPSO. Surplus gas not required for fuel will be returned to a nearby reservoir via a gas injection well. The FPSO will be a converted tanker owned and operated under a service agreement with Norway's Bergesen dy Offshore. It will have a storage capacity of 1.6mn barrels. Including development wells, Woodside is currently planning to drill around 20 wells off Mauritania.

Green light for Thylacine and Geographe

Joint venturers in the Woodside-operated Oway gas project have approved development of the A$1.1bn Thylacine and Geographe gas fields offshore Victoria, southern Australia. The project involves the initial expenditure of A$810mn on the Thylacine gas field in Tasmanian permit T/30P, including the development of a remotely operated platform and a new gas plant to be built near the Iona gas plant located 6 km north of Port Campbell. The Geographe field, in Victorian permit Vic/P43, will be connected to the main offshore pipeline in a later development phase.

The fields are expected to supply some 950bn cf of raw gas, 885 PJ of sales gas, 12.2mn barrels of condensate and 1.7mn tonnes of LPG at the probable (including proved) level over the life of the Otway gas project. First gas is expected in mid-2006, at an initial rate of 60 PJ/y of sales gas – equivalent to 10% of south-eastern Australia's current annual gas demand.

Technip Oceania has secured the EPIC contract for the onshore gas processing plant and onshore pipeline, as well as for the offshore platform facilities. Allseas Construction Contractors will undertake offshore pipelay and subsea tie-in work.

Woodside earlier signed a gas sales agreement with TXU for its share of gas production, around 30 PJ/y, for more than 10 years. Condensate from the Otway project is to be sold to an Australian refinery, while LPG is expected to be sold to distributors operating in Victoria.

Otway project partners are Woodside (51.55%), Origin Energy (29.75%), Benaris International (12.7%) and CalEnergy Gas (6%).

North Sea field redevelopment work

Aker Kvaerner Offshore Partner has landed a major role in the redevelopment of two North Sea oil and gas fields.

The company's Subsea Solutions Group has secured a contract from CNR International (UK) to provide engineering, procurement and project management for the Banff area development project. The agreement consists of two separate scopes of work, in the Banff and Kyle offshore fields.

In order to enhance production in the Banff field, Aker Kvaerner Offshore Partner will provide a manifold structure/SSIV and other facilities as part of a plan to convert the field's 'shut-in water injection' wells to 'gas-lifted' production and to convert one of Banff's existing production wells to gas injection.

In the Kyle field, the company will provide facilities associated with re-routing production from one of the wells to CNR's *Ramform Banff* FPSO. Well 14 in the Kyle field was originally planned to produce to the Banff facility, but it was eventually routed to a FPSO in the adjacent Curlew field. The original Banff to Kyle subsea pipeline/umbilical infrastructure will now be utilised to link well 14 to the *Ramform Banff*. First oil from this phase of the Banff area development is anticipated in the summer of 2004.

Consultation on UKCS infrastructure access

The UK Offshore Operators Association (UKOOA) is consulting stakeholders in the oil and gas industry on fundamental revisions to its code of practice on access to infrastructure on the UK Continental Shelf (UKCS). The industry trade body has been working with the Department of Trade and Industry to secure changes to the code that will open up better access to the pipeline systems in the North Sea.

Access to infrastructure is seen as a key to unlocking future oil and gas volumes in the UKCS, since many of today's new fields are too small to support their own cost-intensive production facilities and need to use existing systems to make them commercially viable.

The new Code aims to secure greater transparency in pipeline tariffs and operation as well as fair and reasonable terms for third-party access to existing infrastructure. All technical data as well as commercial terms and conditions for all deals would be published and the Secretary of State given an automatic invitation to step into negotiations if a deal is not resolved within six months.

The consultation ran until 12 June 2004 and it is hoped that the new Code will be adopted by all UKCS licensees by July 2004.

The consultation document on revisions to the industry's code of practice on access to infrastructure is available on the UKOOA website, which can be found at **www.oilandgas.org.uk**

In Brief

(70.20%, 68.68% and 75.29% in Balmoral, Stirling and Glamis fields).

Europe

The Petroleum Safety Authority *Norway (PSA) has granted Total E&P Norge its consent for partial removal and disposal of the installations on the Norwegian part of the Frigg field.*

The Norwegian Ministry of Petroleum *and Energy reports that 16 companies have received offers to participate in 16 new production licences in a total of 46 blocks or part blocks in the 18th licensing round. The following companies have been offered participation in production licences (numbers in parenthesis): Statoil (9), Norsk Hydro (4), Shell (4), Eni (4), BG (2), Gaz de France (2), ChevronTexaco (2), RWE Dea (2), Pertra (2), DONG (1), Amerada Hess (1), Paladin (1), Esso (1), Total (1), Idemitsu (1) and Revus (1). The following companies have been offered operatorships: Statoil (4), Norsk Hydro (2), Shell (2), Eni (2), Total (1), Pertra (1), Paladin (1), Esso (1), ChevronTexaco (1) and RWE Dea (1).*

North America

Anadarko Petroleum has unveiled a *'refocused corporate strategy' that is expected to deliver higher returns on investments and sustainable 5% to 9% annual production growth.*

US-based Calpine Corporation is *reportedly planning to sell its Alberta gas reserves and has indicated that it may also sell its 25% stake in the Calpine Natural Gas Trust.*

Petro-Canada is to acquire all of the *outstanding shares of Prima Energy of Denver, Colorado, for $534mn (C$719mn).*

ChevronTexaco has sold 13 producing *fields in western Canada to Acclaim Energy Trust and Enerplus Resources Fund for approximately $800mn.*

ExxonMobil (22.5%) reports that the *Llano field in Garden Banks blocks 385 and 386 in the Gulf of Mexico has come onstream at an initial rate of 10,500 b/d of oil and 26mn cf/d of gas.*

ChevronTexaco has agreed to sell a *package of 150 onshore producing assets in the US to XTO Energy for $1.1bn.*

In Brief

Middle East

Qatar Petroleum (QP) and Anadarko *Petroleum have signed a new exploration and production sharing agreement covering block 4 offshore north Qatar.*

Russia & Central Asia

Five of the six partners in the North *Caspian Sea Production Sharing Agreement (NCPSA) in Kazakhstan have exercised their pre-emptive rights in the sale of BG Group's 16.67% interest in the NCPSA, including the Kashagan project. It is also understood that the Kazakh Government has indicated that it believes it has a pre-emptive right to acquire the whole of BG's stake in the NCPSA, on the same terms, including price, as previously agreed with the pre-empting parties, and has expressed its desire to do so.*

Expro International Group has been *awarded a $60mn contract by Exxon Neftegas, operator of the Sakhalin-1 consortium. The contract is for the provision of an early production facility (EPF) to be installed at the Chayvo drilling and production site on the east side of Sakhalin Island, Russia.*

Asia-Pacific

The New Zealand Government is *reported to have proposed a package of measures aimed at increasing exploration for new gas fields to replace the country's depleting Maui reserves.*

Murphy Oil reports that its Kenarong *#1 exploration wells in block PM311 offshore Peninsular Malaysia has discovered oil and gas in multiple horizons, opening up a new play area for the company.*

Shell is reported to be selling half of *its 60% stake in the exploration permits of New Zealand's Western Platform to Electro Silica Group for an undisclosed sum.*

Faced with rising oil prices and security *fears, Energy Ministers from Japan, China, South Korea and the 10-member Association of Southeast Asian Nations (ASEAN) are making emergency stockpiling plans that include creating oil reserves and finding alternative sources for their energy imports.*

UK oil production continues to fall

UK oil production in March 2004 fell by 10.9% against March of last year – the 16th consecutive month where UK oil output fell on a year-on-year basis – according to the latest (2 June 2004) Royal Bank of Scotland *Oil & Gas Index*. It rose on the month by 1.7%, averaging over 2mn b/d. UK gas production averaged 12,070mn cf/d in March, down 2.8% on the year.

Tony Wood, Senior Economist with the Royal Bank said: 'This sustained fall in oil production suggests that UK oil production has peaked. However, sterling revenues are being supported by the current period of high oil prices.'

Combined oil and gas production rose to over 4mn boe/d in March, which was up on the month by 0.7% and down on the year by 6.9%.

Higher oil prices meant that monthly oil revenues were at their highest level since March 2003 at £37mn. The past two months have seen rises in the price of crude oil, with Brent averaging $34.78/b, and WTI averaging $38.16/b and closing above the $40/b mark on 11 separate days.

Tony Wood added: 'Current prices are being driven by a combination of strong demand growth, including very strong crude demand from China, increased concerns about the security of Middle Eastern crude supplies and some market speculation. The tightness of product markets and high geopolitical risks suggests that prices could go higher during the summer, although we expect them to fall in the second half of this year.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Mar 2003	2,251,714	12,420	29.92
Apr	2,092,765	10,868	27.50
May	1,948,620	9,659	25.59
Jun	1,940,265	9,221	27.31
Jul	1,957,888	9,250	28.43
Aug	1,858,409	9,842	29.51
Sep	1,966,800	9,546	26.81
Oct	2,018,972	10,075	28.93
Nov	2,036,012	12,641	28.76
Dec	2,056,469	12,642	29.84
Jan 2004	2,014,906	12,689	31.12
Feb	1,972,891	12,097	30.89
Mar	2,006,160	12,070	33.72

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Further growth forecast for FPS market

Some 138 floating production systems are forecast to be installed with an expected capital expenditure of $32.8bn. This is a 67% growth on the previous five-year period according to Infield Systems' new *Global Perspectives Floating Production Market* report. The report provides an allocation of capex in each year it is forecast to be spent. This introduces into the forecast spend for projects that will come onstream outside the forecast period, which is important when considering their long lead times, states the company.

Strong growth is predicted in the market, with worldwide expenditure in the sector growing from $5.9bn in 2004 to $7.2bn in 2007. Some 139 FPSOs and FPSs are being considered for 2004 onwards. Infield has identified that 65% of forecast projects for the period to 2008 will be converted or upgraded vessels. Globally, the key areas will be Africa ($11.5bn), Latin America ($5.5bn), North America ($5.8bn), Asia ($4bn) and Europe ($3.7bn). The worldwide distribution of spend will be similar to the previous five-year period, with Europe showing more activity. Africa made up 30% of expenditure over the last five years and this will grow to 34%, states the report. North America will show some decline from 27.5% to 18% over the next five years, while Latin America will maintain the same percentage share as the previous five years.

The fastest forecast growth compared with the previous five-year period is in ultra-deepwater, over 1,500 metres, where expenditure is forecast to triple (312%). Deepwater activity between 500 metres and 1,500 metres will account for over half the FPS expenditure, but spend in shallow water will still be important and represents 34% of global FPS expenditure in the period 2004–2008.

For more information, visit www.infield.com

Unocal to develop Bangladeshi field

Unocal is reported to be planning to go ahead with a $292mn plan to develop the large Bibiyana gas field in block 12 in northeast Bangladesh, four years after the initial proposal was rejected by the Bangladeshi Government amidst debates over whether Bangladeshi gas should be exported. The debate over exports has yet to be resolved. However, Bibiyana gas will be used to meet a domestic shortfall as production from the country's five main fields continues to decline while demand continues to rise. Bangladesh is forecast to need between 1,400–1,500mn cf/d of gas from 2006 as it strives to achieve economic growth of up to 7%. At present the country produces some 1,262mn cf/d of gas, against daily demand of nearly 1,300mn cf/d.

Bibiyana gas reserves are put at up to 6tn cf. The Energy Ministry puts Bangladesh's proven and probable reserves at 28.45tn cf of gas, of which 20.5tn cf are recoverable.

Seismic surveys to boost Norwegian output

Contracts worth a combined NKr300mn have been awarded by Statoil for seismic surveys this summer to help optimise output from producing fields off Norway.

About NKr125mn of the total has gone to WesternGeco in Stavanger, with France's Compagnie Générale de Géophysique (CGG) getting work for roughly NKr100mn. Petroleum Geo-Services in Oslo has been awarded contracts adding up to approximately NKr85mn.

The first two of these contractors will be providing 'towed' seismic, with hydrophones trailed behind the survey vessel on cables to register data from the sub-surface. WesternGeco will gather seismic data around the Heidrun and Norne fields in the Norwegian Sea, and the Visund field in the North Sea. CGG's contracts cover the Sleipner area and Statfjord North field in the North Sea, and the Ellida oil discovery in the Norwegian Sea.

PGS is due to supply seabed seismic on the Snorre field and around the Kvitebjørn field which is under development in the North Sea. This entails using listening devices which sit on the sea bottom and record the geophysical data.

First comprehensive audit for TNK-BP

TNK-BP has released the results of the first comprehensive audit of the company's reserves. The independent international firm DeGolyer and MacNaughton conducted the audit to the criteria stipulated by both the United States Securities and Exchange Commission (SEC) and the Society of Petroleum Engineers (SPE).

The audit confirms that as at 31 December 2003, under the standards set by the SEC, TNK-BP's total proved reserves increased from 4.1bn to 4.3bn boe. Of these, proved developed reserves grew from 3.2bn to 3.4bn barrels. Under SPE criteria, total proved reserves decreased from 9.4bn to 9bn barrels. SPE proved developed reserves moved from 6.1bn to 6bn boe. The audit results do not reflect any reserves or resources associated with the ownership of 50% of Slavneft by the shareholders of TNK-BP.

During 2003, TNK-BP grew production by 13.8% to 63.8mn tonnes (average daily production 1.276mn b/d). Based on SEC criteria, TNK-BP replaced 133% of this production with new proved reserves. This replacement ratio is an increase on the average of 25%–35% year-on-year replacement ratio achieved by the heritage companies in 2001–2002. Under SPE standards, TNK-BP replaced 83% of its production.

Stratic Energy farms-in to Turkish project

Stratic Energy is to pay Toreador Resources 25% towards the costs of the Ayazli-1 exploration well offshore Turkey to earn a 12.25% working interest in eight contiguous permits in the shallow water western Black Sea. Toreador will operate the well through its wholly owned subsidiary, Madison Oil Turkey, and pay 75% of the well costs to retain a 36.75% working interest. The Turkish national oil company TPAO is carried through the well, but can exercise back-in rights under Turkish petroleum law to take the remaining 51% interest. Stratic will also pay its 25% share of the costs of the 2D seismic survey, acquired by Madison in 2002, over the four western-most permits.

The operator estimates potential gas reserves on the Ayazli structure to be approximately 350bn cf based upon available information. Moreover, the total resource potential of the area contained within the permits is in excess of 1.5tn cf of gas.

In Brief

***CNOOC's Qikou 18-2 oil field in the** western part of Bohai Bay is reported to have come onstream, producing more than 2,800 b/d of oil.*

Latin America

***Petrobras has commenced production** through the Marlim Sul FPSO in Brazil's Campos Bay. The vessel has the capacity to process 100,000 b/d of oil, store 1.6mn barrels, and compress 2.3mn cm/d of gas, injecting 125,000 b/d of water back in to the reservoir.*

Africa

***First Calgary Petroleums reports that its** MLE-5 well in Algeria has flowed 8,546 boe/d of gas and condensate from three zones. The well confirms the eastward extension of the field. Block 405b, in which the MLE field is located, has gross proved, probable and possible recoverable reserves in excess of 7tn cfe of gas. First production from the MLE field is expected in 2007.*

***State-owned Sonangol (20%) and BP** (operator, 26.67%) have announced a further oil discovery offshore Angola with the drilling of the Venus-1 well in block 31. This is the fourth discovery after Plutão, Saturno and Marte.*

***Kuwait Foreign Petroleum Exploration** Company (KUFPEC) is to acquire for an undisclosed sum Shell's 40% stake in the BG-operated Rosetta Concession in the Nile Delta, offshore Egypt, including the currently producing gas field and onshore/offshore plant.*

***Shell's Sheiba 18-3 discovery well in** the Northeast Abu Gharadig (NEAG) concession in Eygpt has tested up to 1,600 b/d of 36° API oil and 0.9mn cf/d of gas. Sheiba 18-3 is the first commercial oil discovery in the eastern part of the NEAG concession in the Western Desert.*

World

***Opec has increased its production** ceiling (excluding Iraq) by 2mn b/d from 1 July 2004, and a further 500,000 b/d from 1 August. The second part of the output hike is subject to further review at the cartel's 21 July meeting in Vienna. The 8% rise will bring Opec's production ceiling to about 26mn b/d. Oil prices slipped to around $38b after the announcement.*

In Brief

UK

Shell is reported to have cut its oil *reserves for the fourth time this year, restating in May a figure of 4.47bn boe for 2002, up from the 4.35bn boe it gave in April. Meanwhile, Shell UK reports that James Smith, the Head of Executive Resourcing and Organisation for the Royal Dutch/Shell Group of Companies will take up the position of Chairman of Shell UK from 1 August 2004.*

Europe

Statoil has concluded agreements with *US-based Dominion to quadruple its access to extra capacity at the Cove Point LNG import terminal in Maryland on the US East Coast. The deals provide Statoil with access to terminal, storage and pipeline transportation totalling about 10bn cm/y of gas, for 20 years from 2008–2009. The current annual capacity at Cove Point is 2.4bn cm/y.*

North America

Forest Oil of Denver, US, is planning to *acquire all of the outstanding shares of the Wiser Oil Company for some \$330mn, including assumed debt of \$160mn.*

ChevronTexaco has reached an agree- *ment to sell EnerPro Midstream to KeySpan Facilities Income Fund for approximately \$190mn plus certain working capital adjustments.*

Shell Canada has announced that Linda *Cook, President and Chief Executive Officer, will be leaving the company in July 2004 to take up a position as a Managing Director of Royal Dutch Petroleum. Clive Mather, currently Chairman of Shell UK, will be appointed by Shell Canada's Board of Directors to succeed Cook as Shell Canada's President and CEO.*

Middle East

Iraq oil exports from Basra and the *nearby port of Khor al-Amaya have been halted after saboteurs destroyed both pipelines feeding the terminal in mid-June. Exports from Iraq's northern Kirkuk oil fields were stopped earlier in the month following sabotage on a pipeline.*

NEWS Industry

Argentina seeks private investment

In a response to the growing gas shortage, Argentina's President, Nestor Kirchner, has announced a series of measures to address the recent lack of investment by the private sector. The measures, which are to be funded in part by an increase in taxation on upstream companies, include:

- **The creation of a new state oil and gas company, Energía Argentina SA.**
- **Increased investment in the gas pipeline infrastructure.**
- **The creation of an electronic market for gas (known as MEG).**

According to consultants at Wood Mackenzie, the creation of a state oil and gas company has been the subject of much debate in Argentina since the economic crisis unfolded in early 2002. 'However, we consider that the creation of Enarsa will have little or no immediate impact in terms of resolving the current gas shortages. It will take many years to fully establish the new entity, explore for, discover and develop new reserves,' explains Pauline Geddes, a consultant with the firm.

'Benefits to the industry will obviously be seen through the planned improvements to the gas infrastructure and the ultimate deregulation of the gas sector. However, it seems that the new spending plan as a whole has been announced in dissatisfaction at the upstream producers for the recent level of investment in the industry,' adds Geddes. According to Wood Mackenzie, upstream investment plummeted in 2002, when the economic crisis reached its peak, falling by 20% on the previous year. It has been increasing only at moderate levels since then. Prior to this, investment in the sector had been increasing on average by 20% per annum between 1998 and 2001.

'Whilst the initiatives announced by the government are interesting in themselves, the most significant issue for the upstream oil and gas sector is the proposal to partly fund these projects by increasing the tax on crude exports from 20% to 25%,' comments Geddes.

The crude export tax was introduced as an emergency measure at the peak of the economic crisis in early 2002. It was implemented at a rate of 20% and is due to be phased out in 2007. However, adds Geddes: 'The recent announcement to increase the tax raises the question of fiscal stability and whether the tax will actually be removed in 2007 as initially planned. Assuming it is maintained at a rate of 25% to 2007 and beyond, the loss in value to the upstream sector is estimated to be in the region of \$1.7bn.'

Latest developments in the European Union

The dominance of fossil fuels in energy production is set to continue for the next 30 years, even growing a little, the European Environment Agency (EEA)'s latest 'environmental signals' report has predicted, writes *Keith Nuthall*. Despite the European Union's (EU) efforts to promote renewable energy, it is 'not expected to raise its share significantly' of energy production sources, while 'nuclear energy is projected to decline', it predicted. Meanwhile, the European Commission has called for more investment in renewable energies after 2001 figures showed oil accounted for 40% of all EU energy sources, gas 23% and renewables 6%. The EU wants renewables to command 12% of its energy sources by 2010.

In other EU news:

- EU Energy Commissioner Loyola de Palacio has visited Syria, pressing its government to reform its gas infrastructure and regulation so it can play a key role in creating a Middle East-to-Europe network. The EC sees Syria as a key link, notably in the so-called Arab pipeline, linking Egypt to Syria and the Lebanon through Jordan. De Palacio noted that connections between Syria and Turkey could also 'open up the enlarged [eastern Europe] EU energy market'. De Palacio encouraged technological cooperation, and the 'convergence of regulatory and normative standards'. She also visited the Lebanon to discuss developing its energy sector.
- Russia has promised to raise its natural gas price for industrial users so it 'covers costs, profits and investment needed for exploitation of new fields' in a wide-ranging trade deal with the EU helping Moscow's World Trade Organisation (WTO) membership application. Prices would rise from the current \$27–\$28 (per 1,000 cm) to between \$37–\$42 by 2006 and \$49–\$57 by 2010.
- The EU has pressed the Ukraine at an EU-Ukraine Cooperation Council for further energy sector reform, supporting construction of the Odessa–Brody oil pipeline.
- The EC has expanded its 50mn CIVITAS programme, providing 35% funding for projects reducing urban road transport to eastern Europe, including cities from Estonia, Hungary, Poland, Romania and Slovenia.

NEWS Industry

Birthday Honours recognition

A number of personnel in the energy sector have been recognised in the Queen's Birthday Honours list this year. They include Hugh Robert Collum, Chair, BNF, who has been made a Knights Batchelor for services to the nuclear industry. OBEs have been given to Michael Baunton, President of Perkins Engines, for services to the Automotive and Engineering Industries; Roy Franklin, Chief Executive, Paladin Resources, for services to the UK oil and gas industries; Prof John Knott, Member, Health and Safety Commission, Nuclear Safety Advisory Committee, for services to Nuclear Safety; Janet Yvonne Reed, National Manager, British Gas, Wales, for services to Economic Development in Wales; Albert Schofield, Director, Mining Information and Coal Services, Coal Authority, for services to the coal industry; and Frances Elizabeth Taylor, Superintending Inspector of Nuclear Installations, Department for Work and Pensions.

Meanwhile, MBEs have been awarded to John Clarke, Data Acquisition Services Manager, Babcock Engineering Services, for services to the defence industry; Leslie Clarke, Electrical Engineer, National Grid, for services to the MoD; John Craven, Secretary, Emissions Trading Group, for services to climate control; Prof Richard Harrison for services to Solar Research; Jacqueline Hill, Administrative Support, Energy Markets Unit, DTI; and Joseph Bariamu for services to PNG Power.

Sinopec to expand East China operations

Sinopec is reported to be stepping up efforts to expand its natural gas operations in eastern China's Shandong Province, aiming to make it the company's largest gas consuming centre. The company is understood to be planning to supply Shandong with some 6bn cm/y of gas by 2010 from four sources in the central, north and northwest of the country, and from imports of LNG.

It is thought that the proposal may trigger competition between Sakhalin in Russia, Iran, Australia and Indonesia – all of which have expressed an interest in supplying Sinopec with gas an initial rate of 3mn t/y, rising to 5mn t/y in the future.

At present, Sinopec supplies gas to Shandong from its Zhongyuan gas field in Henan Province. Sinopec's largest gas field, Zhongyuan produced 1.7bn cm of gas last year. The company plans to raise production to 2bn cm within the next 18 months. Before LNG imports start arriving in 2007 or 2008, additional gas will be piped to Shandong from PetroChina's West-East pipeline, in which Sinopec has a 5% stake, and from the Ordos Basin in the north. Sinopec is also developing the Daniudi gas field in Inner Mongolia, which has proven reserves of 250bn cm, and is preparing to build a pipeline from it to Shandong. The field could supply 1mn cm/y of gas by 2006.

Equatorial Guinea LNG project on track

Marathon Oil and Compania Nacional de Petroleos de Guinea Ecuatorial (GEPetrol), the national oil company of Equatorial Guinea have achieved key milestones in the development of the companies' LNG project in Equatorial Guinea, which remains on track to begin first shipments of LNG in 4Q2007.

All major commercial agreements including the upstream gas supply agreement, the LNG concession agreement with the Government of Equatorial Guinea and the shareholders agreement for the newly formed Equatorial Guinea Train 1 operating company have been finalised. In addition, the Government of Equatorial Guinea has approved and published an LNG Decree Law securing the fiscal terms and conditions for implementing the project. GEPetrol will hold a 25% stake in the project and will fund its participation through the dedication of oil revenues from current oil production. These funding arrangements are expected to be finalised in the near future, at which time the companies will announce a final investment decision.

The LNG project will produce a minimum of 3.4mn t/y. BG Gas Marketing Ltd (BGML), a subsidiary of BG Group, will purchase production from the project for a period of 17 years.

In Brief

Russia & Central Asia

***Sakhalin Energy has signed its first LNG** sale and purchase agreement (SPA), with Kyushu Electric Power Company.*

***A Moscow court has effectively** annulled Yukos' attempted takeover of Sibneft. Yukos, now left with a 34.5% interest in Sibneft, is expected to appeal the ruling.*

Asia-Pacific

***CNOOC is reportedly planning to** develop an LNG project in north China's Hebei Province.*

***The Malaysian Government is under-**stood to have ruled out creating a large national oil stockpile.*

***The Board of Petronet has reportedly** approved the doubling of capacity at the Dahej LNG receiving terminal in northwest India from 5mn t/y to 10mn t/y. Petronet Chief Executive Suresh Mathur has also confirmed that India will buy 5mn t/y of LNG from Iran under a 20-year contract scheduled to begin in 2010. Iran's Pars LNG project is aiming to produce 8mn t/y from 2009.*

***Chinese Petroleum Corporation (CPC)** has outlined plans for the construction of what will be Taiwan's second LNG receiving terminal. The facility will be sited on the western side of the island, in the port of Taichung, and is due to be commissioned in 2009. It will have an annual throughput capacity of 3mn t/y and is likely to cost some $720mn.*

Latin America

***Petrobras recently delivered 44,000** tonnes of LPG to Japan – its first to what is a new market for the Brazilian company. The cargo, imported by Idemitsu, was valued at $15mn.*

Africa

***The International Finance Corporation,** the private sector of the World Bank, is reported to have announced a $45mn investment in Egypt's developing gas sector that will support the exploration and production activities of the Egyptian subsidiaries of US company Merlon Petroleum. Merlon has a 50% stake in the El Mansoura concession and 54% in the Qantara concession.*

In Brief

UK

***Walsall-based Keyfuels, part of UK** fuel management company CH Jones, is to manage some 1.5mn l/y of fuel for Univar's HGV fleet of over 70 vehicles. Univar will close its own yard facilities and move to re-fuelling on the CH Jones network. Meanwhile, Morrisons, one of the UK's largest supermarket chains, has joined the CH Jones fuel network. The deal means that all of the existing 113 Morrisons service stations will accept both Diesel Direct and KeyFuels cards. With the integration of the Safeway forecourts following the recent merger, Morrison's fuel network could grow to over 300 sites.*

***Centrica is to acquire the 652-MW** Killingholme CCGT power station in North Lincolnshire for £142mn.*

***Centrica has announced the reduction** of around 1,450 positions within its organisation, which, following redeployment, use of fewer contractors and the removal of vacant positions, is expected to lead to approximately 850 job losses. The changes are expected to yield an operating cost benefit in excess of £90mn in 2005.*

***UKPIA, the trade association repre**senting the main oil refining and marketing companies in the UK, has published its* 2004 Statistical Review *of the downstream oil industry. The* Review *is available on UKPIA's website at* **www.ukpia.com**

Europe

***Foster Wheeler has been awarded** two engineering, procurement and construction (EPC) contracts by ERG Raffinerie Mediterranee (ERGMED) for the expansion of the existing power station and a new ultra-desulfurisation unit at ERGMED's owned and operated ISAB refinery (South Plants) at Priolo Gargallo, Italy. Both plants will be completed by the end of 2005.*

***Sports utility vehicles (SUVs) could be** banned from Paris city centre during peak pollution periods within 18 months following a resolution recently passed by the city council.*

North America

***HydrogenSource, a US developer of** fuel processing systems, is to be dis-*

NEWS Downstream

Call to suspend UK gas oil duty

The Federation of Petroleum Suppliers (FPS) has called on the UK Government to suspend an increase on gas oil duty, that is due to take effect on 1 September 2004. In his 2003 Budget, the UK Chancellor increased the excise duty on gas oil by almost 35% to 4.22 p/l, his justification being that it would 'encourage the use of alternative, more environmentally-friendly fuels'. In this year's Budget, he further increased the excise duty on gas oil by 57% to 6.64 p/l on the ground that it would 'further reduce the potential for oils fraud, in combination with the other oils fraud strategy measures'. According to FPS, that is a total increase of 112% over two years.

The FPS believes that the only direct effect that this tax increase has is to place an additional financial burden on rural communities, many of which are dependent on gas oil as a source of heat and power, and do not have the option of changing to mains gas.

'Both of the Chancellor's justifications for increasing duty on gas oil have been greeted with scepticism by the oil distribution industry,' said FPS Chief Executive Susan Hancock. 'We have asked the Treasury to consider suspending the duty increase on gas oil, due to come into effect on 1 September. With the recent high prices of crude oil, the Chancellor is already getting unexpected additional revenue from North Sea oil. The high crude prices have increased the prices of gas oil to end users, to the point where it will affect the economy of rural communities. It would be disastrous to add further burdens on these communities and should no longer be necessary because of the extra revenue from North Sea oil.'

'Regent' branding to make a UK comeback

The 'Regent' name is set to return to UK forecourts with the launch of a new proposition for independent retailers, available from Texaco's network of equity distributors. The strong heritage of the Regent name was a familiar sight on petrol pumps until the late sixties. 'The modern Regent proposition now combines a 21st century image with the traditional values of friendly, local service and value for money,' says Texaco. In addition to the modern graphics, Regent offers a network of 28 regional offices in the UK providing retailers with effective support and fast delivery, a credit card package, quality fuel and lubricants products, as well as local marketing and sponsorship assistance.

Andrew Cox, Manager ED Sales Europe, commented: 'The new Regent package is designed to meet the needs of independent retailers who are looking for a strong, recognisable brand that will add value to their business. Regent offers a modern image with a strong heritage that motorists will recognise, backed up with local service and quality products. We believe there are a significant number of independent retailers who are looking for precisely the kind of package Regent offers.'

Statoil expands Scandinavian fuel ops

Statoil is to acquire ICA's 50% interest in the Scandinavian fuel retailing operation Statoil Detaljhandel Skandinavia for an undisclosed sum. This agreement requires the approval of the European Union competition authorities, which is expected to be forthcoming in late June or early July.

Statoil Detaljhandel Skandinavia was established in 1999 as a 50:50 joint venture between Statoil and ICA of Sweden. It operates almost 1,400 service stations in Scandinavia and has about 23% of the market. The new retailing business will embrace operations in nine countries in Scandinavia, Poland, Ireland, Russia and the Baltic states; have 8,000 employees and annual revenues of NKr40bn; and serve more than 1mn customers every day.

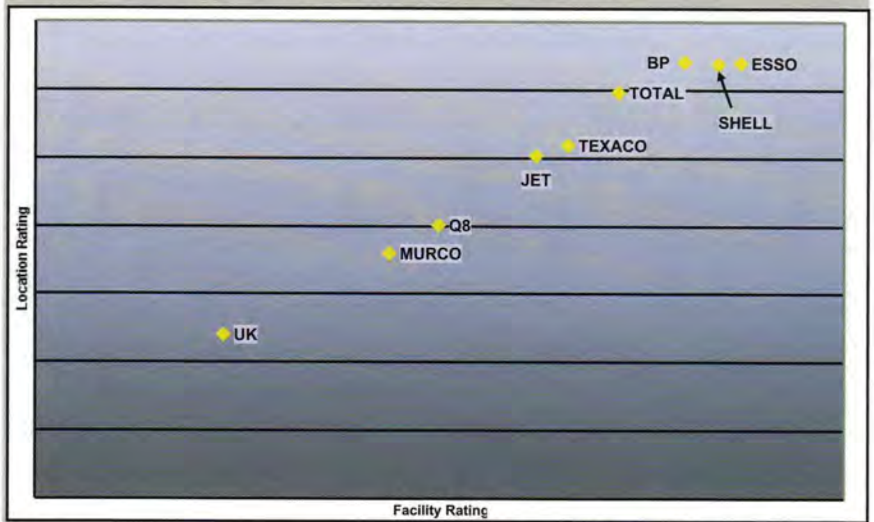
Relative strengths of fuel retail brands

Last month, *Petroleum Review* looked at the overall competitive positioning of some major fuel retail brands across Europe in respect of average site facility and location strengths. This technique developed by Catalist measures a site's retailing strengths based on location factors (traffic flow, accessibility, demographics etc) and facility factors (number of fuelling positions, shop type, size, product categories).

This month focuses on the relative strengths of the major brands in the UK, excluding hypermarket sites, and looks at the combined scores of dealer- and company-owned sites. Interestingly, there appears to be very little differentiation between Shell, BP and Esso in terms of location strengths; however, there is in terms of overall facility strengths. Texaco appears to be the weakest of the major brands and this probably reflects the high percentage of dealer-owned sites, while BP has a similar percentage of dealer sites.

Another point of interest is that the UK has the second largest number of brands in Europe, totalling 167, many of which are one site per brand. The country with the largest number different brands in Europe is Spain, with 227.

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



Source: Catalist Ltd, 2004. All rights reserved.

Fleet card services fail to meet needs

Fleet business represents a major share, some 25bn/y, of fuel card providers' revenues, making customer retention extremely important. However, a new report from independent market analyst Datamonitor reveals that despite many fuel card services being highly valued, under 50% of fleet managers across Europe make use of the majority of them.

The research involved detailed interviews with 225 fleet managers across Belgium, France, Germany, Italy, the Netherlands, Spain and the UK, in connection with their fuel card preferences and take-up rates (usage) of 10 services.

The report also reveals that 20% of fleet managers are unsure as to what services are available, making it clear that communication is poor and the current offerings are failing to meet fleet managers' needs. Furthermore 30% of fleet managers indicate they will have switched their fuel card supplier by 2005. While price is the main reason behind switching, 19% of customers indicated they would switch for a better service, and 8% for a better network coverage. 'By providing services that customers value and use, fuel card suppliers can minimise customer switching and related costs and are more likely to acquire a broader customer base,' says Datamonitor.

These issues need to be addressed quickly given the additional discontentment resulting from current fuel price rises. Datamonitor cautions fuel card suppliers, saying that they must go back to basics and start by trying to understand which services are valued, and by whom, in order to improve return on investment.

In Brief

solved following a joint decision by the company's owners, UTC Fuel Cells and Shell Hydrogen.

ConocoPhillips and Excelsior Energy *have signed a development and technology licensing agreement for an integrated gasification combined cycle (IGCC) facility featuring ConocoPhillips' E-Gas technology. Excelsior's Mesaba Energy Project will be located on the Iron Range of northeastern Minnesota and will be one of the cleanest and most efficient coal-fired power generating facilities in the world. The first unit of the project will be capable of producing a net output of approximately 532 MW of electricity and is expected to be operational in 2010.*

Middle East

Foster Wheeler has secured a pro*gramme management services contract from Saudi Aramco and Sumitomo Chemical of Japan for the planned development of a large, integrated refining and petrochemical complex at the Red Sea town of Rabigh, Saudi Arabia. It is claimed that, once implemented, the facility would be one of the largest integrated complexes ever to be built at one time. A total of 2.2mn tonnes of olefins, along with large volumes of gasoline and other refined products, will be produced.*

Russia & Central Asia

Texaco Overseas Holdings has agreed *to sell its 50% share in the TNK & Texaco Lubricants Company joint venture to the TNK-BP group, subject to regulatory approvals.*

Asia-Pacific

Foster Wheeler has been awarded a *professional services contract by CSPC – a 50:50 joint venture between Shell and CNOOC (China National Offshore Oil Corporation) – under which it will provide technical support services for at least the next two years for the Nanhai petrochemicals project in Guangdong in China.*

Indian Oil Corporation (IOC) is report*edly planning to launch 1,000 'Extra' branded service stations by September 2004 as a part of an aggressive marketing strategy, boosting the total network to over 10,000 sites by end-2004.*

In Brief

BP reports that it has added fuelling facilities to provide hydrogen on a trial basis at one of its Singapore retail filling stations, making it the first company in the world to provide the environmentally friendly fuel at an existing retail site, alongside conventional fuels.

At least four firms, including GAIL of India, Petronas of Malaysia and British Gas, are reported to have bid for supplying gas and LNG to Reliance Energy's 3,740-MW gas-fired power plant at Dadri in Uttar Pradesh, India. Reliance Industries is also understood to have bid for the supply of natural gas from its giant Dhirubhai fields in Bay of Bengal. GAIL plans to supply LNG from Iran, while Petronas proposes to supply LNG from South-East Asia. British Gas could supply gas from its Panna/Mukta and Tapti fields offshore Mumbai.

Latin America

Petrobras has launched its Podium-branded gasoline in Argentina, the first fuel in the country to be marketed with a RON 100 octane index.

Africa

More than half of all petrol sold in sub-Saharan Africa is now unleaded, says the UN Environment Programme (UNEP), which wants leaded fuels phased-out in the region by 2006. Kenya has announced plans to switch to fully unleaded petrol by 1 January 2006, reports Keith Nuthall.

NEWS Downstream

Powergen to become E.On Energy

On 5 July 2004 Powergen, the UK's largest electricity supplier to the business sector, will take the brand name of its German owner E.On. 'This will help Powergen to tap into a powerful pan-European brand and overcome its electricity-only image,' comments analyst Datamonitor. 'With the UK set to become a net importer of gas in the next few years, and the growing role of gas in the country's energy sector, this is set to boost E.On Energy's (as Powergen's I&C business will now be known) competitive positioning. By dropping "power" from its name (except for its mass market and small business customers), the company will undoubtedly try to win a similar position in gas to that it enjoys in electricity.'

'As far as price is concerned, E.On Energy will now be able to draw more fully on the parent company's trading and risk management expertise, keeping price levels in line with the market trends and offering pricing formulas that are flexible and diverse enough to meet the diversity of customer requirements. The company should also be able to offer improved multi-fuel and added-value offerings.'

Distrigas 'under threat' in Belgium

Distrigas has been threatened by the opening of the Belgian gas market and is looking abroad to counteract the losses at home, reports analyst Datamonitor. By the end of 2003, Distrigas had lost almost 8% of the Belgian market to entrants from the neighbouring markets. The largest of these were Gaz de France, BP Belgium and Germany's Wingas, who won business in the large-user segment, which has always been the focus of Distrigas' retail activity. A number of new entrants into the gas market, such as Electrabel, Luminus (a Centrica subsidiary) and Dutch-based Nuon are also targeting smaller customers, which are directly supplied by Belgium's local distribution companies. Gas sales to the local distributors represent over a quarter of the company's total throughput, hence the development of competition in this sector will further erode Distrigas' overall market share.

As a result, Distrigas is now focusing on international expansion, with an aim of winning a 5% share of the European gas market. It is already well represented in northern France, which is easily accessible from Belgium, and in Spain, where, unusually for western Europe, tanker-transported LNG is competitive against piped gas. However, in Datamonitor's opinion, the company does not have sufficient competitive advantages to compensate for domestic losses through an aggressive and successful international policy. Overall, the analyst expects the company's market share of physical sales to decline further in the medium to long term. 'Managed retrenchment is on the cards and Distrigas should look for marketing partnerships but also expect its arbitrage trading to become the main profit centre of a contracted business,' comments Datamonitor.

UK Deliveries into Consumption (tonnes)

Products	†Apr 2003	†Apr 2004	†Jan–Apr 2003	†Jan–Apr 2004	% Change
Naphtha/LDF	159,957	252,421	856,734	845,462	–1
ATF – Kerosene	840,141	803,877	3,147,642	3,193,502	1
Petrol	–	–	–	–	–
of which unleaded	1,656,248	1,596,979	6,298,690	6,332,589	1
of which Super unleaded	65,124	75,495	265,397	270,218	2
ULSP (ultra low sulphur petrol)	1,591,124	1,521,484	6,033,293	6,062,371	0
Lead Replacement Petrol (LRP)	19,498	6,566	78,250	29,223	–63
Burning Oil	281,539	367,687	1,653,909	1,898,869	15
Automotive Diesel	1,359,620	1,553,528	5,516,649	6,157,598	12
Gas/Diesel Oil	492,751	522,219	2,100,802	2,147,023	2
Fuel Oil	187,139	208,318	804,563	827,522	3
Lubricating Oil	77,207	67,141	282,841	254,950	–10
Other Products	581,033	885,534	2,639,831	3,381,539	28
Total above	5,655,133	6,264,270	23,379,881	25,068,277	7
Refinery Consumption	334,740	307,188	1,604,567	1,659,687	3
Total all products	5,998,873	6,571,458	24,984,448	26,250,891	5

† Revised with adjustments

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

Cash for gas

Photo: Kogas

The LNG market is enjoying an unprecedented period of expansion. But this growth is going to cost a lot of money – who is going to foot the bill? And are lenders happy with the way the industry is changing? *Peter Mackay reports.**

Speak to any energy analyst and the forecast that emerges is of a future demand pattern reliant ever more heavily on natural gas. World energy demand is going to continue growing, there is no doubt about that. The emergence of high-population developing countries into the global industrial markets means that power demand from new industries and household energy requirements from a growing middle class will underpin overall consumption growth. We are already witnessing tightness in the oil market and rising oil prices because producing countries cannot keep up with demand; natural gas – so far more lightly exploited than crude oil – is an obvious means of helping to plug the gap.

Global natural gas consumption in 2003 is estimated by research company Douglas-Westwood to have been some 2.6tn cm. Speaking recently at a conference in London, the company's LNG analyst Steve Robertson said he expects a consistent increase in natural gas usage to a figure close to 4.8tn cm/y by 2025. Significantly, though, he said that pipeline supplies are likely to peak soon and, whereas last year 93% of natural gas production was delivered by pipeline, that proportion will have fallen to 69% by 2025, with LNG accounting for 26%. That suggests that LNG trade, which last year reached some 150bn cm of natural gas, will have to expand eight-fold to 1.2tn cm/y over the next two decades.

This growth forecast implies that the LNG business will have to double in size within six years. As Gary Clarke, head of Industrial Transportation Finance at ANZ Investment Bank, said at the same conference, which was organised by *Lloyd's List* Events, about $10bn will be needed every year in order to finance this expansion. This money is available, he said, but the way it is provided in the future will be very different to the LNG sector's experience so far.

New generation LNG

The problem is that, with the step-change in the size of the LNG business, there is a corresponding shift in the way it is being organised. In the traditional model, each LNG trade was set up as a separate project and financed as such. Financial planning would take into account the cost of natural gas acquisition, the cost of setting up and running the liquefaction and regasification plants, and the cost of transportation over the lifetime of the initial sales contract, which was normally 20 or 25 years.

Although the sums of money could be extremely large – several billions of dollars – lenders could be persuaded to get involved on a project finance basis. Participants in the chain normally included one or more major multinational oil company and state-owned or government-backed interests. The shipping leg was underpinned by timecharter arrangements over the whole period of the sales contract, and cashflow was further guaranteed by the 'take or pay' nature of the agreement between buyer and seller.

Although some old hands in the LNG business are still sceptical that it will follow the model of the crude oil trades, it is now undeniable that this old model is breaking down. Liquefaction plants have been and are being built before firm commitments have been signed to take the LNG output. Independent shipowners and major oil companies have placed orders for new ships without timecharter commitments – according to Drewry Shipping Consultants as much as 27% of the current LNG orderbook can be described as 'speculative'. And putative importers can get a long way down the road of planning and approvals before lining up supply contracts, feeling relatively safe that LNG will be available from somewhere.

As Gary Clarke said during the *Lloyd's List* conference, lenders now see it is possible to finance LNG shipping separately from supply projects. However, this means that deals will not be done on the basis of 20-year contracts and lenders will have to look more closely at residual ship values. Furthermore, it militates against the development of a true 'spot' market in LNG ships as stability of transport pricing is vital to lenders' models.

There are other changes, too. Rather than dealing with top-rated multinationals and state-backed companies, lenders will have to assess a rather different risk when providing finance to the emerging players in the market, which include domestic US power companies, Chinese state interests and Indian oil and gas corporations. Also, the financing model becomes more complex as individual LNG producers sell into very different markets. The two Qatari projects, for example, are selling LNG to Asia, Europe and North America; each of these trades has very distinct economics and shipping demands and each market responds to its own set of governing factors.

Finding a comfort zone

As the market changes, so does the location of risk. In the traditional LNG model, the buyer took the volume risk and the seller took the price risk. Transport risk, shared between buyer and seller, was minimised by the use of very expensive, well-maintained vessels. The entry of independent shipowners with no interest in the LNG supply contract shifts much of the transport risk. It also means that both buyer and seller can offload some of their 'natural' risk while accepting some of the other side's risk. Thus, if a buyer cannot take the volume specified in the sales contract, he may well be able to sell a cargo on to another buyer, while accepting some risk that the price received is not attractive. A more likely scenario is that the buyer requires additional cargoes and will be able to use the independent shipping sector to arrange delivery of spot or short-term cargoes but without the control over prices he enjoys with the baseload supplier.

These changes have implications for the ways in which lenders view the market. James Ball of Gas Strategies outlined a new approach to project finance during a presentation at the LNG14 conference in Doha in March this year. To maximise limited recourse financing, he said, lenders seek to create a 'low risk zone' around a project, with clearly defined parameters. Under the new LNG model, with both buyer and seller looking for greater flexibility, this will probably mean that debt levels will have to be lower, since the parameters traditionally used by lenders to assess risk are less clearly defined.

One way to approach this problem, Ball said, would be to look at project revenues as a series of 'risk bands'. The lower the risk level, the greater the deemed revenue stream from the project and the higher the potential debt level. In cases with a high risk level, lenders would only be comfortable with a much lower potential debt level. By creating different risk bands, project sponsors and lenders could clearly understand the real risks in order to settle on the highest debt level that all parties are happy with.

What the options are

At the *Lloyd's List* conference, however, Gaurav Seth, Director of LNG projects at ANZ Investment Bank, explained just how complex the cashflow waterfall is in an LNG value chain. That chain is only as bankable as the quality of cashflow it generates, which is ultimately reliant on the payment certainty of the LNG buyer – the regasification plant. When looking at the elements of the value chain in isolation, then, each beneficiary would need to ring-fence cashflow at source if multiple financings are to be arranged.

Project finance has proved to be the natural model for the LNG business in the past. It is lending based on cashflow with limited recourse to sponsors and its availability depends on cashflow quality and the project structure – something that LNG could offer lenders. However, as Nick Roos, Managing Director of Deutsche Bank's asset finance and leasing unit in London, explained at the same event, there are alternatives. As the LNG model changes, these alternative finance mechanisms will come into their own.

Although ideal for LNG financing, project finance has its drawbacks. It is time-consuming and costly to arrange, requires a great deal of monitoring and, for strategic reasons, demands shared control of a project. Asset-based corporate finance, on the other hand, is relatively easy and cheap to arrange. However, it will require a first-ranking ship mortgage, will depend on corporate creditworthiness rather than cashflow, and places a heavy burden on the balance sheet of the borrower.

Other financing mechanisms have not yet been used in the LNG world, although there are possibilities, especially for financing shipping separately from LNG projects. Bank debt has not so far been a major feature of the maritime sector but could be used, although there would be restrictions on debt levels. Financing through the capital markets is an option for larger shipowners – around $1.65bn was raised through high-yield debt markets in 2003 for shipping clients, Roos said – but again this has not yet made any impact in LNG. Leasing, which requires similar credit characteristics as corporate loans, has been used in recent LNG ship financings. The UK lease market is particularly attractive, he said, as it offers up to 100% financing of assets, flexibility to change the agreement, and tax advantages.

Another alternative that is bound to feature heavily in future LNG projects is Islamic financing. This is an area that is not well understood in the traditional finance markets but, as Javed Ahmad, Director of HSBC Bank in the UAE, said at the *Lloyd's List* conference, there is a growing supply of Islamic liquidity that investors would like to see placed with high-quality, regional projects.

Islamic finance is an ethical mode of funding that derives its principles from Islamic law ('Shariah'). Its most distinctive element is the prohibition of interest, and it is also characterised by an emphasis on equitable contracts, the desirability of profit sharing and a prohibition on 'gambling' or uncertainty. It favours equity financing over debt, as the latter relies on the payment of interest. Asset-backed debt finance can be designed, however, on the basis of sale or leasing contracts that provide fixed income alternatives to conventional debt financing. The capital provider needs to have ownership of the asset, if only briefly, and bear the risk that comes with that ownership. Islamic bonds can also be designed, based on asset-backed debt financing.

As the capital cost of LNG projects comes down, and the flexibility of supply and purchase contracts increases, all these alternative funding methods are likely to come more into play. Lenders will be encouraged to think outside the relatively narrow confines of traditional LNG financing in the future.

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Turning gas in to liquids

Mojgan Djamarani **takes a closer look at gas-to-liquids (GTL) technology – a technology that has yet to see widespread commercial application despite the environmental benefits of GTL diesel being well recognised.**

Gas-to-liquids (GTL) is a chemical process that converts natural gas in a stranded reservoir or associated gas that otherwise would be flared (thereby releasing greenhouse gases to the atmosphere) into fuels and petrochemicals that can be transported at ambient conditions.

Although the technology involved in GTL has been around for more than 70 years and the environmental benefits of GTL diesel are well recognised, GTL technology has not seen wide commercial application. One deterrent has been the high capital expenditures required for GTL plants and another, maybe more decisive factor, has been the oil price. GTL becomes economical only if oil prices remain high – below a certain level it will not yield an acceptable return on investment.

Economic case for GTL

Many of the dry gas finds are too small, are located too far away from industrial centres or contain significant amounts of carbon dioxide (CO_2), making them uneconomical to exploit and of low value. Alternative methods of exploiting these stranded gas reserves are necessary... and this has been an impetus to the development of GTL technology.

This is particularly the case in Russia, where most of its gas is now found in isolated distant regions on the Yamal Peninsula, the Arctic Shelf, East Siberia and the Far East that are too far from the existing transmission networks. The cost of pipeline transmission per unit of energy is very high and makes the development of even the largest of these remote gas finds uneconomical, according to a paper presented at last year's World Gas Conference in Tokyo by a team from VNIIGAZ. By 2030, Gazprom is to deliver 530bn cm/y of gas, with almost 90% of its reserves now located in the above-mentioned remote regions. In the oil-producing provinces associated gas is flared as there are no gas delivery systems. Alternative gas transportation options to pipelines are considered as either too expensive in the case of LNG, except for the very large fields located on the coast or the continental shelf, or as unviable in the case of methanol as its market is already saturated. GTL plants are considered attractive as they can also be integrated into the oil refining industry (see **Table 1**). Russian companies are currently studying GTL projects with Tulsa-based Syntroleum Corporation.

Indices	GTL	LNG
Price of product	$220/t	$140/t
Sales volume	5.5mn tonnes	6.4mn tonnes
Capex	$3.4bn	$2.3bn
Capex for tanker construction	$300,000	$1bn
Total capex	$3.7bn	$3.3bn
Location of market	Rotterdam	Zeebrugge
Distance to market	4,000 km	4,000 km
Internal rate of return	15%	12%

Source: VNIIGAZ, see **www.syntroleum.com**

Table 1: Comparison of economic indices between GTL and LNG projects for a large gas field on the Yamal Peninsula

Company	Conversion Efficiency MMbtu / bbl	Capital Expenditure $MM	Total Cost of Production(2) $ / bbl
Conoco	8.20	1,423	23.10
Company 'A'	8.44	1,671	28.68
Company 'B'	9.39	1,744	31.71
Company 'C'	9.76	1,350	26.79
Company 'D'	10.20	1,291	26.73

Figure 1: Chem System's comparison of GTL technologies of fully-integrated companies1

Another impetus to the development of GTL technology in recent years has been the liberalisation of the gas and electricity markets. Furthermore, the greater volatility of the gas price, making its sale by long-term contracts more difficult, has created major obstacles for the financing of long-distance gas pipelines and LNG projects. Although GTL is seen as a complementary rather than a competitive technology to LNG, it has a few advantages over LNG – including the fact that it is cheaper to transport GTL fuels than LNG.

According to VNIIGAZ: 'GTL creates the possibility of a much more efficient transportation system for liquid products at ambient temperatures and pressures including the use of existing oil pipelines, standard tankers and storage facilities.' GTL products have unconstrained markets with no special contractual arrangements required for their sale. Moreover, the large-scale economies of natural gas transport via pipeline or LNG has historically led to a lack of flexibility in contractual arrangements – although this is changing. In addition, LNG assets are tied up to specific economic transactions. GTL products, on the other hand, can be sold by short-term contracts with a reduced interdependence between buyers and sellers. However, in general the two alternatives service different markets.

Environmental case for GTL

The pressure of environmental legislation in the developing economies for restrictions on the flaring or venting of associated gas, coupled with an increase in control of harmful emissions in the transport sector in the developed market economies, has also led to increased research in gas-based conversion technologies. Compared to other gas derivative fuels such as LPG and CNG, GTL has lower emissions. It yields clean fuels that are ready to be sold on the market and have a less damaging impact on the environment when burnt.

The GTL process produces diesel fuel with a higher cetane number and is compatible with the existing diesel engines and distribution infrastructure. Moreover, given the high environmental standards imposed, GTL products can be hydrocracked in a simple low-pressure process to produce products that are free of sulphur and aromatics and which can be blended into refining stock as superior products with less impact on air acidification and pollution. GTL naphtha can also be used in fuel-cell applications because it is sulphur-free and has a high hydrogen content.

GTL technologies

There are two broad technologies for GTL to produce synthetic petroleum products. These are termed 'direct' and 'indirect'. The direct conversion of methane yields liquid products such as alcohols, olefins and aromatics. This method is wrought with technical problems as the high stability of methane molecules creates a series of technical problems to make the chemical reactions involved stable. To date, none of the direct conversion processes have proven economic or of commercial value.

The other method is indirect conversion via synthesis gas (syngas), which is technically easier. It can be carried out via Fischer-Tropsch (F-T) synthesis and involves three steps. First, natural gas is converted into syngas (a mixture of hydrogen and carbon monoxide) by partial oxidation, steam reforming or a combination of the two processes. This is called the auto-thermal reforming process (ATR). In the second step, syngas is converted into liquid hydrocarbons (HC) through the F-T process in a chain growth reaction of carbon monoxide (CO) and hydrogen (H_2) on the surface of a heterogeneous catalyst. The catalyst is either iron-based or cobalt-based and the reaction is highly exothermic. The temperature, pressure and catalyst determine whether a light or heavy syncrude is produced. To make the products of commercial interest, a third step, hydrocracking, is required. This breaks down the heavy long-chain hydrocarbons into smaller molecules according to the products that are to be obtained, such as naphtha, diesel oil, paraffin, lubricant oil etc.

Company	Project	Location	Cost	Details
Sasol	Oryx GTL	Qatar	$800mn, FEED contractor – Foster Wheeler $30mn	34,000–24,000 b/d GTL fuel for diesel engines, 9,000 b/d naphtha, 1,000 b/d LPG. Start-up 2005.
Sasol Chevron	Oryx expansion	Qatar	$1.4bn	Expand production to 100,000 b/d by 2009, by adding three new trains.
Sasol Chevron	Under discussion	Qatar	$4.5bn	Upstream/downstream integrated GTL luboil project with six trains using Sasol's Slurry Phase Distillate Process. Start-up 2010.
Petro SA	Mossgas complex	South Africa	–	47,000 b/d of mostly gasoline.
Shell	Bintulu GTL	Malaysia	–	12,500 b/d increasing to 15,000 b/d through debottlenecking. Using Shell's Middle Distillates Synthesis (MDS) process, produces naphtha, kerosene, diesel, solvents, etc.
Sasol Chevron	EGTL	Escravos, Nigeria	$1.3bn	34,000 b/d of naphtha and GTL diesel, primarily for the European market.
GTL Resources		Burrup Peninsula, Western Australia	$450mn	1 mn t/y methanol plant. Construction to begin 1Q2004.
ConocoPhillips		Ras Laffan, Qatar	$5bn statement of intent signed	80,000 b/d of GTL diesel, naphtha and LPG for the Asia-Pacific and European markets. Planned start-up 2009/2010.
Shell	Upstream/Qatar downstream integrated GTL project		$5bn FEED contract – JGC. $50mm to be completed by May 2005	To develop a block within offshore North field, with production of 1.6bn cf/d. 140,000 b/d onshore GTL plant using Shell MDS process to produce diesel, naphtha, LPG and condensate. First stage start-up 2009, at 70,000 b/d.

Table 2: Summary of present GTL projects

Future of GTL

The direct conversion processes may present the best long-term prospects, but currently remain unproven. In 2001, BP signed a 10-year contract with the universities of California Berkeley and Caltech, allocating $1mn/y to each to conduct research utilising direct conversion routes.

The three stages of indirect conversion have been well studied individually and are in commercial use, and efforts are now focused on an optimal combination of the three that would permit the reduction of costs of the commercial production plants. In the meantime, GTL project costs remain high, which has led to the commercial application of GTL technology by only the big energy companies that have the financial resources and are already involved in other aspects of energy production in the oil and gas producing countries. Furthermore, it can be difficult to raise finance for such projects as the GTL industry does not yet have an established track record. For example, in 2002, Syntroleum had to cancel its Sweetwater GTL development in north-

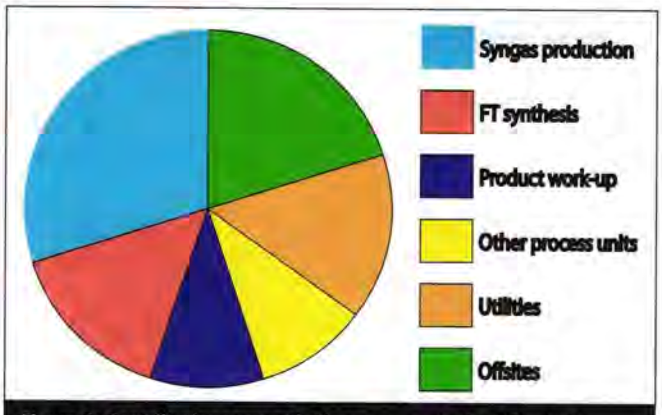

Figure 2: Contributions towards the capex cost of a GTL plant based on Foster Wheeler's past experience
Source: Foster Wheeler, Offshore World, Oct–Dec 2003

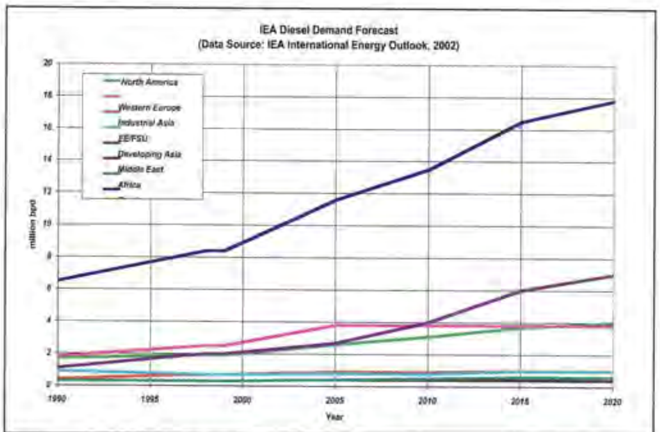

Figure 3: IEA Diesel demand forecast
Source: IEA International Energy Outlook, 2002

western Australia because it could not raise adequate financing. The company had been leading research into lowering the cost of syngas production by developing a process whereby atmospheric air rather than oxygen is used in the production of syngas, thereby eliminating the cost of the air separation plant.

While capex is a significant factor in the economies of GTL, according to a recent Wood Mackenzie report the ultimate decision to invest in GTL may rest with a company's perception of future oil prices. While LNG projects offer a higher net present value, a tightening of the LNG markets will drive the industry toward GTL. A significant reduction in capex and sustained high oil prices may lead to a dash for GTL but, more likely, it is argued, there will be a steady build up to GTL projects.

Estimates of crude oil prices necessary to allow positive economic returns from GTL projects vary widely, but most typical estimates indicate that prices would have to average over $20/b on a sustained basis to lead to commercialisation. Uncertainty about oil prices, rather than the technology itself, has been the stumbling block to GTL investment. However, according to Michael Corke, Vice President at Purvin & Gertz, the main driver for GTL project development should be viewed primarily as gas monetisation. The economics of integrated upstream/downstream gas field GTL plants tend to be better than those for a GTL plant on its own. Depending on location and whether the feedstock is from a wet gas field, the sale of co-produced condensate and LPG could boost the economics of the GTL project substantially. In such cases, Corke estimates that a GTL project could be economically justifiable with oil prices as low as $15/b. According to BP Global Gas Technology, integrated rates of return range from 22%–38% depending on a Brent crude price of $16–$24/b compared to 12.5%–30% for GTL plants.

According to a cost comparison prepared by Chem Systems for Conoco in 2001, the variation in total cost of production per barrel of product can vary from $23.10 to $31.71 (about a 30% variation) for the same capacity of plant. The variation is mainly explained by the technology deployed and the cost attributed to the value of the gas. See **Figure 1**.

Figure 2 is indicative of the contributions towards the capex cost of a GTL plant based on Foster Wheeler's past experience.

Demand for GTL products

According to the IEA's 2002 *International Energy Outlook*, world demand for diesel will rise from 12mn b/d in 2005 to 18mn b/d by 2020, with the fastest growth expected to take place in the developing Asian economies (see **Figure 3**). The main potential market for GTL diesel is Europe – although, according to Corke, diesel from GTL is too low in density to be used without being blended with heavier, 'conventional' diesel to meet current European specifications. Shell is trying to position itself ahead of its competitors in capturing a large part of the diesel market. Its 'Pura Diesel', which is a blend of its GTL transport fuel from its Bintulu plant mixed with conventional diesel and an additive, is already on sale in Thailand and its similar 'Diesel 2004' is being marketed in Athens, Greece.

The restrictions on the burning of associated gas by means of the application of fines or even a higher tax base, as in Nigeria, offers large supplies of gas at very low prices. The flaring of associated gas represents a cost for the oil producer, who would be willing to make its utilisation viable, even if the price received for the product does not totally re-numerate his investment. As a result, an important niche market for GTL projects has been emerging, seeking to utilise reserves that have a negative cost of opportunity.

Capital costs for GTL projects currently tend to be around double that of refineries, at between $20,000 and $30,000/daily barrel of capacity. GTL projects need to service capital costs whereas many refineries are operating with largely depreciated assets. However, the environmental restrictions imposed on the quality of fuel represent a great incentive for GTL. First, these demands represent an increase in cost for the traditional refineries. The situation is further made more difficult in a context of growing competition and tighter margins. Still, it is not in the long-term competition between GTLs and refineries that the most important incentive lies – it is the opening of niches in the short-term market. GTL fuels used for transport should attract, in theory, premium prices as they have been shown to reduce vehicle exhaust emissions. Demand for GTL fuels should be anticipated to grow firmly, especially for diesel fuels, with the growing emphasis and legislation for low-sulphur and aromatic fuels in Europe and the US.

The foreseeable future

According to the Instituto de Economica –UFRJ*, for the foreseeable future, GTL has two likely options. One is the market for ultra-clean fuels without sulphur, aromatics and heavy metals. But, if the other, non-GTL solutions make production of ultra-clean fuels viable, GTL would have to directly compete with refineries and its advantages might disappear. In this case there should be considerable reduction in the cost of GTL production to make GTL plants competitive and give priority to scale economies.

The other market is for chemical specialities that offer much higher prices than those of the fuels, but demand smaller volumes of products limited to niche applications.

**The renewal of the gas-to-liquids technology: perspectives and impacts'*, www.ie.ufrj.br

An industry in transition

With the dawn of a new millennium, the North American gas industry began a major transition, involving a set of changes that will continue not only through this decade, but into the next as well. Wood Mackenzie's *Bob Fleck*, Vice President Gas and Power Consulting, and *Ed Kelly*, Vice President North American Gas and Power, report.

The Siren's song of natural gas being a plentiful, inexpensive, environmentally friendly, domestic source of fuel for electric generation and industry has spurred the greatest build of new gas-fired generation facilities in North American history. Ironically, just as many of these new facilities approached operational status, the US gas industry began a dramatic shift from having surplus production to struggling in efforts to replace depleting reserves. Gas prices have moved from a \$2–\$2.50 trading range, to a \$3.50–\$10 trading range in a matter of only a few winter seasons.

The commitment to gas for power generation throughout North America will drive both industries well into the next decade as the gas industry struggles to feed this potentially huge appetite for gas.

Power – a predetermined destiny

North America, and the US in particular, has rapidly expanded its power generation fleet, and nearly all of the new plants are gas fired. By 2005, nearly 240,000 MW of new generation will be online, representing an overall growth in generating capacity in the US equal to 32% of the total generating capacity in 1999 (see **Figure 1**). Most regions of the US now have sufficient capacity to last into the next decade.

As the US economy begins to grow, power demand will grow with it, and the new fleet will meet the majority of the new demand. A large portion of this load growth will be relatively non price-sensitive in that, if needed, these plants will pay the price of the fuel required to generate. Due to this relative in-elasticity, the price of gas will at times be less of a factor than the availability of gas, thus allowing the electricity industry to out-bid other, more traditional sources of demand, especially in the industrial sector, forcing them out of the gas demand picture. By 2010, almost all the growth in gas demand in North America will be power based, as demand in other sectors will actually remain stagnant or even shrink.

Supply constraints

The industrial sector, already challenged by a combination of a slow US economy, high gas prices and global competition, will struggle to maintain demand levels even equal to the already reduced 2003 level of 19bn cf/d. This weakening in industrial demand has been caused primarily by switching to residual fuel oil, industrial product prices that have not matched the increase in natural gas prices, cutbacks in American production, and general belt tightening and cost cutting across all manufacturing sectors. Without these challenges, industrial gas demand could have been expected to reach 22–26bn cf/d by 2010. With high prices continuing to encourage offshore production, changing to alternative fuels, and conservation, industrial demand overall instead will struggle to remain near 19bn cf/d in the US.

Residential and commercial demand will not grow through the remainder of this decade, despite an actual increase in the absolute number of gas customers. Efficiencies of new appliances that will replace older, less efficient models in homes in the midwest and the northeast especially, will cause the actual use per customer to decrease faster than the demand from new customers. Further, a higher sustained price for gas will encourage increased conservation efforts. The combined result will be a 6% decline of gas demand from these sectors in total.

New gas sources needed

With the exception of the Rocky Mountain and deepwater Gulf supply regions, all other major producing regions are either in a state of permanent decline or minimal growth. Increases in production in the Rockies will be nearly eight times greater than any other historic supply basin between 2003 and 2010, the result of the many unconventional supplies located in the region. The supply gap in fact must

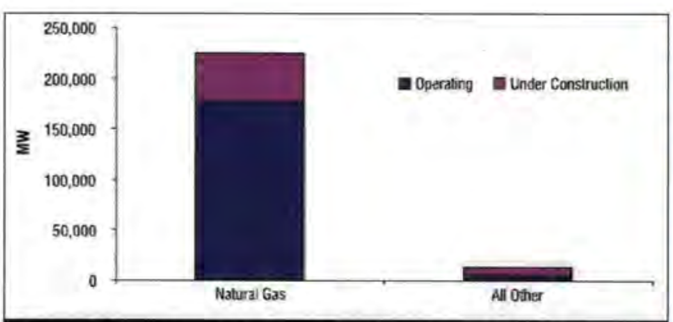

Figure 1: New generating capacity by technology, 2000–2005

Wood Mackenzie recently completed a study entitled *Falling Short – The Growing Challenge to Supply the North American Natural Gas Market through 2010*, which looks at the North American gas industry through 2010. The study looks at the growing dependence of the electricity industry on natural gas and the ability of the gas industry to respond at a time of apparent productive declines in domestic gas supplies.

For details www.woodmac.com/enmulti-client.htm

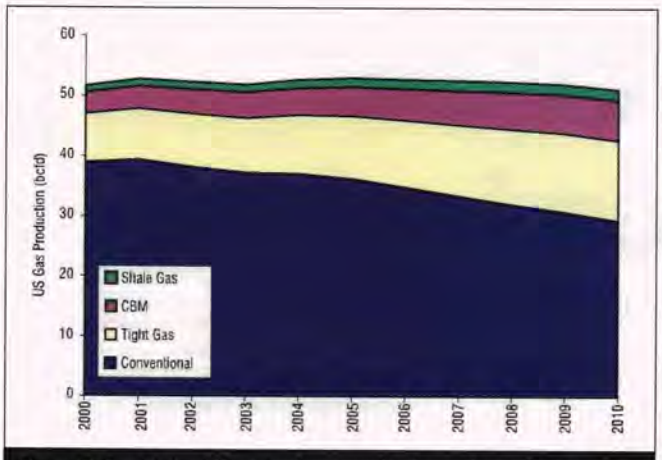

Figure 2: Sustaining US natural gas production – dependent on the unconventional

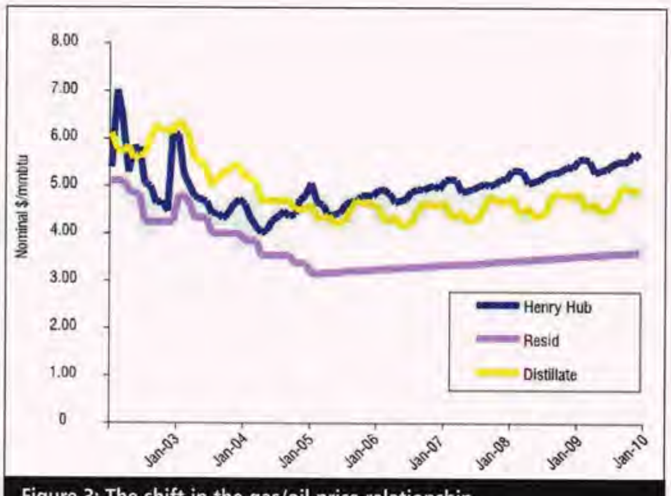

Figure 3: The shift in the gas/oil price relationship

be filled by non-traditional sources, including the unconventional tight gas, coalbed methane and shale reservoirs, as well as the deepwater Gulf of Mexico, deep drilling in the shallow Gulf, and increased imports of LNG (see **Figure 2**). In the near term, frontier supplies from the Arctic will not be available to alleviate the growing struggle for supply.

Despite increasing, the non-traditional supplies of natural gas will still barely be able to keep supplies level through 2010, leaving an opportunity for LNG imports to help fill the gap between growing demand and stagnant supply. By 2010 Wood Mackenzie expects LNG imports to grow by nearly five times, to 6bn cf/d. Continued tightness of the supply-demand balance in North America will continue to attract increased volumes of LNG well beyond 2010, with the siting of new import facilities and expansion of existing facilities.

Gas – the 'premium fuel'

Tight supplies and a marginal power generation demand that is at times inelastic will force gas prices to remain strong, on average between $4 and $5.50 in nominal terms through 2010. In the near term, prices will average near the lower end of the range as new supplies from the Rockies and the deep waters of the Gulf of Mexico, combined with adequate storage levels and increased LNG imports, add to supply.

Traditional demand will continue to be constrained, even during the early years, contributing to keeping gas prices between the price of residual oil and distillate most of the year. However, a shift will occur post 2005, in which the two to three month per year pricing above distillate that has occurred over the past several years will become more of a year-round phenomenon. (See **Figure 3**.)

The upper range of the band between residual and distillate prices, an effective constraint on gas prices much of the year since the 1980s, will become a floor by 2006 as a consequence of many forces, a few of which have been mentioned and include:

- Demand pressure from power generation load growth will continue to build, and in fact accelerate later this decade.
- Increasing numbers of core heating customers will increase weather-driven on-peak demand, despite increasing efficiency per customer.
- Environmental pressures on oil burn are likely to intensify.
- Power producers will continue to pay the 'market price' for gas due to the 'pass-through' of fuel costs prevalent in the industry.
- Most new generation, unable to switch fuels due to competition during construction (which minimised the capital investment in fuel flexibility) and burdensome environmental permitting, is unlikely to invest the capital and time required to build new switching capability.

Production in the deep water peaks and begins to decline near the beginning of 2006, and the challenge to overcome these declines is a major driver moving gas prices above distillate beyond 2006. Increases in LNG will not be large enough or fast enough to compensate for the declines in production. Neither will increased production in Mexico or Canada. Even the loss of 4–9bn cf/d of potential traditional demand will not bring prices back to their historic levels relative to the oils band. In fact, both significant builds in LNG import capability and the construction of an Arctic pipeline are required before a return to the traditional oil/gas pricing relationship is likely, if then.

This change in pricing will result in the return of some mothballed oil steam generation, as the efficiency gains of new gas generation can not overcome the gas price premium over residual and, at times, distillate. This will be a factor primarily in the northeast, Florida, and Entergy, although other regions will be affected if the premium over distillate dictates.

Without an upper band constraining gas prices, we can expect increased volatility, especially during periods of coincident peaks of the gas and the power systems. Regionally, the infrastructure will continue to become strained under peak conditions and prices for incremental gas will rise accordingly – as it has in New England already with $60+ gas prices in January 2004. Risk management will become a necessary tool for consumers that can not tolerate the extreme swings, as such swings will become more and more commonplace in the future, creating opportunities for marketers and financial players willing to take on those risks for consumers.

Paying the price

Gas consumers, especially power generators, heard the Siren's song during the late 1980s and into the 1990s, and heeded the words to those songs. Now, with the rules of the game changing due to declines in domestic productive capabilities, many are paying the price.

An extended period of high and volatile gas prices must now be endured and, until alternatives can be developed, similar volatility will be seen in power prices as gas increasingly sets the marginal price of power. The challenge for the gas industry is clear – to bring the supply to bear while the market potential still exists.

Utilities are at the frontline of emissions

Investors and financial institutions across the globe are becoming increasingly alert to climate change risk. Utility companies, as leading emitters of greenhouse gases, are in the frontline, reports *Richard Gledhill*, Global Energy Corporate Finance & Recovery Leader at PricewaterhouseCoopers (PWC).

EU-ETS – a brief explanation

The EU's ratification of the Kyoto Protocol requires total emissions of greenhouse gases to fall to some 92% of their 1990 levels in the period 2008–2012. The introduction of an emissions trading scheme (known as the EU-ETS) is a key EU policy response to this challenge. Together with companies in four other sectors (refineries, ferrous metals, pulp and paper, and building materials), power generators will be subject to a 'cap-and-trade' system of emissions control.

Allowances will be determined by national government allocations across the EU (initially based on historical CO_2 emissions, but, after 2008, the scheme will be extended to cover the other five greenhouse gases). These will be freely transferable between companies or tradable on the open market, with the objective of incentivising lower cost emissions abatement.

A three-year first phase, from 2005 to 2007, is designed to embed the scheme ahead of full implementation, scheduled to coincide with the Kyoto target period of 2008–2012. Failure to cover emissions with allowances will lead to fines of 40 per tonne of CO_2 in the first phase, rising to 100 per tonne from 2008. As well as incurring fines, companies will still be required to purchase emissions rights in the ensuing period to cover the shortfall. The possibility of carrying over excess allowances from 2007 (the end of the first phase) to 2008 (the beginning of the next) is currently under discussion, but is likely to be forbidden (as proposed under the draft UK and German national allocation plans), or at least restricted.

Companies will be able to use emission-based credits flowing from so-called Kyoto Protocol Flexible Mechanisms – ERU (emission reduction units) from joint implementation (JI) and CER (certified emission reductions) from the clean development mechanism (CDM). In this way, emission reductions achieved through approved projects in developing countries can be used to meet EU obligations up to a certain limit.

The original EU thinking was that these JI/CDM credits could be used in the second phase of the scheme, from 2008 onwards. But the European Parliament has signalled that it may favour allowing them to be linked from 2005. A decision on this is expected later this year.

Each country will need to establish a national registry of allocations and develop the necessary legal codes while, at the EU level, a pan-European hub needs to be established, ensuring a smooth link between national registries for intra-European transactions.

Allowances must be distributed free, although governments have the ability to auction 5% in the first phase of the scheme and 10% in the second phase. For the first phase, it seems unlikely that auctioning will be widely adopted. ●

The EU's carbon dioxide (CO_2) cap-and-trade scheme starting on 1 January 2005 will cover more than 12,000 installations in five different industrial sectors (see **box**). It is the first multilateral trading scheme of its kind and power generation will be at the forefront – the power sector accounts for 55% of the emissions covered by the EU Directive.

Yet, despite their exposure, the boards of many utility companies appear to have been slow at integrating the consequences of climate change into their business strategy. The results of PWC's recently published *Global Utilities Insight 2004* report* show that less than one in five European utility companies has a strategy in place to address the implications of climate change and emissions trading. Two-fifths of those surveyed are still developing their strategies and one in five has no strategy at all. Progress is even slower in other markets. Only one in eight of the US companies surveyed, for example, has a climate change strategy in place.

The carbon clampdown

Governments around the world are introducing compliance measures that limit CO_2 emissions. The EU25 (the current European Union member states and accession countries), Canada and Japan have all ratified the Kyoto Protocol and are developing emissions trading frameworks and other incentives to encourage clean power generation technologies.

Even in the US and Australia, where the federal governments have turned away from Kyoto ratification, greenhouse gases (GHGs) are beginning to be addressed at a state level. In the US at least 15 states have passed legislation or have policies to address CO_2 emissions under consideration. In Australia, the state-based New South Wales (NSW) GHG Abatement Scheme, which imposes mandatory GHG benchmarks on all NSW electricity retailers, began on 1 January 2003.

Stakeholder warnings

Stakeholder momentum is prompting companies to be much more proactive in considering their GHG opportunities, risks and exposure. Representatives of leading institutional investors in the US, for example, have initiated an 'Investor Network on Climate Risk' calling for better disclosure of climate change risk. The Network has launched a 10-point plan calling on the Securities and Exchange Commission to force companies to disclose how climate change could affect them and to require investment managers to factor climate risk into their recommendations.

The EU-ETS is also sharpening the focus on investment and credit risk arising from CO_2 emissions. Ratings agencies have become alert to the potential credit-negative risks of the scheme. Similarly, investment bank analysts have been busy trying to analyse the impact of the EU directive on individual companies. Carbon risk is fast becoming part of the currency of analyst and investor scenario planning and dialogue.

The ultimate stakeholder is the consumer. Green consumer trends have been with us for some time but have yet to mature into the mainstream market orthodoxy. The direction of consumer change, though, is set and its momentum is likely to build if severe weather events continue to increase in frequency. This momentum is underlined by the decision of a leading Hollywood studio to feature climate change as the latest disaster movie scenario and entertainment figures such as the Rolling Stones to declare their concerts 'carbon neutral'. Similarly, the travel industry is increasingly giving customers the option of paying a premium to offset emissions from their holiday flights.

Green energy options have become an established part of the utility company product mix. The development of the EU-ETS, and the accompanying media and non-governmental organisation (NGO) focus on the level of emissions, will itself stimulate increased consumer awareness of their supplier's emissions track record. At the same time it will help to offset the extra cost of green energy alternatives. The opportunity for energy companies to position themselves in the future energy market as a provider and manager of clean energy solutions, with services such as energy management, dispersed self-generation, sustainable energy solutions and carbon compensation products, is significant.

EU countdown challenges

In Europe, the timetable set by EU legislators is demanding, both for regulators and for the market. Directive 2003-87 sets the overall framework for emissions allowance trading but it is for the individual national states to translate it into national law and, crucially, to draw up plans for how allowances are to be allocated to individual installations. By the end of summer 2004 each country will have submitted its national allocation plan to the EU and these will have been scrutinised to check for State Aid Rule infringements and coherence with Kyoto and EU Directive targets.

The method of allocating emission rights will be extremely important in determining the net financial impact on companies. It will also play a part in shaping strategy and tactics. The initial consultative documents from individual governments suggest that there may be significant differences between states, which will present arbitrage opportunities for companies. In particular, the treatment of new entrants seems to differ between the UK and Germany.

Early signals

Even ahead of the exact rules of the EU-ETS being known, trading of allowances has already begun. Not surprisingly, this pre-compliance trading has been thin, as companies use relatively low volume trades to gain experience in the market, frame agreements with counterparties and test their internal systems. The trend so far has been an upward drift in bid-offer spreads, with prices nearly doubling from 6/t CO_2 in spring 2003 to more than 12/t CO_2 in winter 2003. However these initial figures relate to a very illiquid market, with less than 50,000 tonnes of CO_2 allowances traded every week.

Once national allocation plans and compliance rules become clearer, the market is likely to witness greater trading activity and experience genuine price discovery.

New risks

The EU-ETS will deliver a new layer of factors to integrate into utility company risk evaluation frameworks. Ahead of the scheme's implementation companies have to manage the risk associated with uncertainties around allocations and market arrangements. They should also be factoring in the implications for investment and M&A (mergers and acquisitions) activity, as well as equipping themselves for the ongoing risks that they will face in connection with trading, compliance, monitoring and settlement. The risk framework for emissions trading will also need to be sensitive to the possibility of 'shock risks' such as grid crises, extreme weather conditions, market shortage or government intervention.

Emissions trading will pose direct and dramatic consequences for the strategic positioning and asset portfolio management of individual companies. The critical influences for utility companies include the CO_2 emission intensity of current generation, the company's geographical footprint (since allocation policies will vary according to countries' different Kyoto burden-sharing agreements and the impact on power prices will depend also on the regional fuel mix and the degree of interconnectivity with other power markets), vulnerability to weather risk, access to clean power financial incentives, and the balance between marginal abatement costs and the cost of purchasing new emissions allowances.

Shifts will take place in the configuration and the structure of energy production. Even in scenarios where

Figure 1: Embedding the key processes within the company *Source:* Emission Critical 2004, *PricewaterhouseCoopers*

companies get allocations that protect their high emitting installations, there will be incentives to change the configuration of these installations and the new merit order will affect investment plans. Different pricing points will have an impact on the strategic fuel mix decision. A switch from coal to gas, for example, could reduce the cost of emissions by 5/MWh (assuming 500 kg CO_2/MWh at 10/t CO_2). At the opposite end of the spectrum, a dry season forcing the substitution of coal for hydro could create an additional 9/MWh cost.

Factoring carbon into investment decisions, however, will not be straightforward, with uncertainties as to allocations from 2008 and the whole climate regime beyond 2012. The interaction between carbon, fuel choice and electricity prices will be complex. Variations in national rules for new entrants and plant closures and the potential for gaming in relation to future allowances (the timing of reductions may impact future allocations) add further layers of complexity.

New opportunities

Emissions allowance trading presents European utility companies with some unique opportunities. Many have developed significant energy trading expertise and are already establishing a track record and experience in early emissions trading. At the same time, some of the capabilities that will be important in the new market, such as managing weather risk and real-time forecasting of supply and demand, are already integral to the utility skill set.

Power generators know their emissions a day ahead, which gives them opportunities to intervene on the market before counterparties are aware of any imbalance. These factors argue for a more proactive trading strategy to deliver value beyond mere compliance. In turn, this will have competitive implications for companies in the rest of the sector.

Underpinning these trading advantages, utility companies appear to be in a better position than companies in other sectors to pass the cost of carbon on to their end-customers, although their success in doing so will depend on regulatory considerations. An important part of this equation will be the extent to which governments are prepared to view higher retail prices as a key component of their climate control strategy.

Higher prices provide an incentive for energy efficiency. The extent to which utility companies are successful in persuading regulators to stand aside from intervention may rest in part on how far they can become active players in promoting energy management, conservation and sustainability.

The top 10 European utility companies will be in a particularly strong 'market-making' position since they will control more than 30% of all EU allowances allocated. By contrast the remaining 70% will be allocated to more than 5,000 companies, the vast majority of whom have a single installation and no trading capabilities.

Setting a strategic lead

Early planning and preparation, both strategically and operationally, is vital. Yet, as we have seen, nearly half of European utility leaders that we surveyed are not yet confident enough to say whether they will be active traders in the allowance market and a significant minority does not yet have a strategy for climate change.

The starting point for any company is

continued on p24...

Emissions trading may lead to increased power prices

The latest *European Power Price Report* from Waltham, Massachusetts-based Global Insight claims that the impact of the European Union Emissions Trading Scheme (EU-ETS), while increasing electricity prices in all major European markets, will be materially different across these countries due to their very different mixes of generating plants.

'The EU-ETS, scheduled for implementation in January 2005, will make it more expensive to generate electricity using carbon-emitting fuels such as oil, gas and coal by putting a price on carbon dioxide (CO_2) emissions. Despite the fact that at least 95% of the available emissions permits will be allocated free in the first phase of the scheme (2005–2007), the price at which those allowances are subsequently traded will directly affect operating decisions,' comments WEFA. 'As a result, the notional or opportunity costs of the emissions will still be passed through to consumers in the form of higher prices.'

Generators with the largest CO_2 emission allowances will receive the largest revenue windfall. The size of the windfall to each generator plant will depend on the market CO_2 price and the volume of emissions credits it receives against its actual emissions.

According to the study, Germany and the UK will see the largest electricity wholesale price rises, due to their strong reliance on coal plants to generate electricity, resulting in electricity prices increasing as much as 40% by 2010. Power prices in Italy are forecast to rise 15% given current CO_2 market prices, but could increase by up to 30% if those prices double. The smaller forecast impact on Italian prices, when compared to those in the UK and Germany, are due to its unusual mix of zero-carbon hydropower and high-carbon oil-fired plants. Spain and the Netherlands are forecast to fare much better, with electricity prices rising only between 10% and 20% by 2010, depending on the market price for CO_2. Both countries primarily rely on gas-fired low carbon emitting power generation. Spain, in addition, also benefits from its hydropower plants.

The study also found that Italy, Spain and the Netherlands will not be able to rely on emissions reductions from their power sectors to make progress against their Kyoto obligations and will need to import their CO_2 reductions from other countries.

Dr Trevor Sikorski, Head of Global Insight's Power Service observed: 'The expected price rises and windfall gains of some generator plants raises a serious question: Will governments stand by and allow industrial and household consumers to pay the higher electricity rates, with the main financial beneficiaries being the power generators' shareholders? If so, the manufacturing industry will be dealt a further blow with the inevitable result of direct and indirect job losses.'

A key factor shaping the power markets in the next few years will be environmental policy. The introduction of the EU-ETS, the generous incentives for greater renewable power across Europe and the application of the large combustion plant directive (LCPD) will all have a significant impact on plant mix and the type of new plants being built.

'It highlights starkly the great problems governments will face in resolving conflicts between environmental and social objectives, both of which figure very high on the electoral agenda,' added Sikorski.

More information on the *European Power Price Report* is available at **www.globalinsight.com/eupower**

A balanced portfolio

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

Lundin Petroleum is an independent oil and gas E&P company with producing assets in France, Tunisia, the Netherlands, Norway, Venezuela, Indonesia, the UK and Ireland. In addition, there is a significant upside potential within these areas of operation, including undeveloped oil and gas discoveries and a range of ongoing exploration programmes.

With further exploration assets in Sudan, Iran and Albania, Lundin Petroleum has a balanced portfolio of world-class assets. The company has existing proven and probable reserves of 72mn boe and a forecast net production for 2004 of 29,000 boe/d. (See **Figure 1**.)

North Sea core area

In the first half of 2004, Lundin completed the purchase of DNO's assets in the UK, Ireland and Norway. The acquisition is extremely important for the company, increasing its forecast production to 40,000 boe/d by year-end 2004 and doubling reserves to 137mn boe. Lundin had also acquired a number of production interests in Norway in 2003 following its purchase of a 75% shareholding in OER Oil.

The major element of the 2004 acquisition programme is DNO's UK offshore assets. Current production is from the mature Heather and Thistle fields, but the big value-generating asset is the Broom oil field in which Lundin has a 55% operated interest. The three Broom production wells are already predrilled and installation of the subsea pipeline is currently taking place. First production from Broom is expected in 3Q2004 at a rate in excess of 20,000 b/d.

Lundin's main asset in Norway is the Alvheim development (15%), operated by Marathon and which is expected to begin production in 2006 at a rate in excess of 80,000 b/d of oil. During 1Q2004 Lundin also had exploration success with the Hamsun discovery, in which it holds a 35% stake. The discovery, located close to the Alvheim development, was appraised with three sidetrack wells and a fast-track development is now expected, utilising the Alvheim production facilities.

On the downside, Lundin has had disappointing results in Ireland – which represented less than 10% of the DNO acquisition value – with production from the Seven Heads gas project well below budget. It appears that the geological model used for development planning was incorrect and, as such, the recoverable volumes from the field will be less than originally forecast.

Operational overview

With 11 production licences, output from France's Paris Basin during 2004 is forecast at over 2,900 b/d net to Lundin Petroleum, with proven and probable reserves of over 19mn barrels. The largest field is Villeperdue, which produces 1,900 b/d of oil. Lundin also holds four exploration licences in the Paris Basin.

Meanwhile, the Aquitaine Basin contains four producing fields, the largest being Courbey. The net 2004 production forecast for Lundin's assets is over 1,800 b/d of oil, with proven and probable reserves of 7mn barrels. A new development well, Les Pins 5, has been successfully drilled and completed. The well tested over 2,000 b/d on natural flow and is now producing.

The Netherlands is a mature gas region, with stable offshore and onshore production offering attractive fiscal terms. Lundin has proven and probable reserves of 8.1mn barrels and a net 2004 production forecast of over 2,300 b/d.

Meanwhile, net production forecast for 2004 from the company's Tunisian operations is 1,600 b/d of oil, with proven and probable reserves of 6.2mn barrels (including the Oudna field). There are also a number of undeveloped discoveries offshore Tunisia, in which Lundin has an interest – including Oudna, Birsa and Zelfa, which tested significant volumes of hydrocarbons and are likely to be developed. Indeed, a development plan for the Oudna field has already been submitted to the Tunisian Government.

Lundin Petroleum also has a 12.5% holding in the Colón block in Venezuela, in which eight fields have a forecast 2004 net production of over 2,700 b/d. Proven and probable reserves are put at 9.1mn barrels. The block has significant upside potential for further discoveries and production enhancement. The operator is Tecpetrol.

The company is also involved in producing fields located in Indonesia's

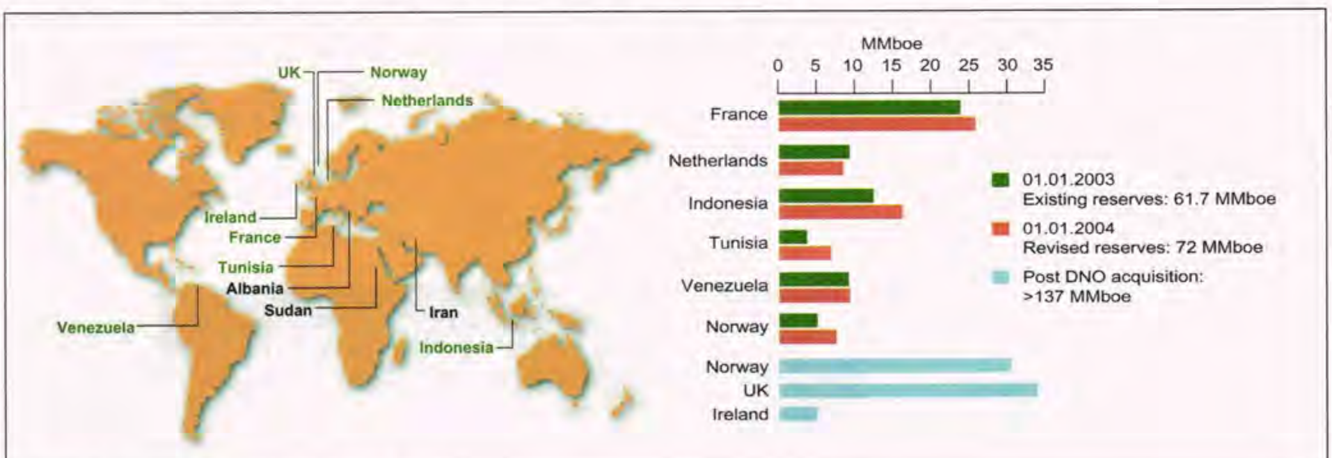

Figure 1: a) Lundin Petroleum's core E&P activity b) reserves summary

Salawati Basin and Salawati Island. Net forecast production for 2004 is approximately 2,600 b/d, with proven and probable reserves of 16.1mn barrels. Lundin has interests in four other prospective exploration licences, which contain undeveloped oil and gas discoveries and prospects on trend with existing fields.

Together with OMV (50%, operator), Lundin (50%) recently signed a new production sharing contract (PSC) for exploration and production of oil and gas in a new block called 'Durresi', offshore Albania. The Lundin Petroleum-operated block D PSC will be terminated and the remaining work commitment transferred to the new block. The work programme for the first four years of the Durresi block PSC includes reprocessing of existing 2D seismic, the acquisition of new 3D seismic and the drilling of one exploration well.

Meanwhile, in Sudan, Lundin has a 24.5% non-operated interest in block 5B. The block is situated in the prolific Muglad Basin, where over 1bn barrels of oil have been discovered to date and approximately 300,000 b/d are being produced from blocks north of block 5B. The block contains numerous large prospects and leads identified from earlier seismic acquisitions.

Onshore Iran, Lundin holds a 30% interest in the Edison International-operated Munir exploration block. The block is located in the prolific petroleum system of the Zagros Fold Belt next to and on trend with a number of major oil fields. The first exploration well (Sehqanat deep-1) of a two-well programme reached a total depth of 2,786 metres in May 2004. The results of a testing programme are expected this month.

Future prospects

Although Lundin proposes to continue with its proven growth strategy through acquisition and exploration, it now expects a major portion of its growth to be generated internally.

The company has a number of projects that will deliver near-term production growth, including the UK Broom development, Alvheim and Hamsun in Norway, and the Oudna development in Tunisia.

In tandem, Lundin has an active exploration programme for 2004, with wells to be drilled in Iran, Indonesia, France and the Netherlands.

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... continued from p22

to decide what value strategy to pursue. In the long-term, enhanced shareholder value will only accrue to those companies that succeed in determining and implementing a clear and successful strategy for managing both their overall climate change risk and their CO_2 exposure. They will need to be able to plan and manage a range of issues that could create corporate financial risk.

Corporate climate change strategy needs to draw on skills across the company, with a convergence between environmental, financial and legal disciplines. As the start date for the EU-ETS draws near, utility companies must ensure that they align their approach to carbon trading with other key processes in the company (see **Figure 1**). Those companies that do not move quickly to show that they are addressing all these questions in a coherent way will risk being downgraded by investment analysts or credit rating agencies.

Emissions allowances can be held by companies for three purposes:

- for compliance, to cover actual emissions;
- for hedging, to manage market price risk between emission and delivery; and
- for trading, to generate profits from future price movements by buying and selling allowances, credits and related derivatives.

Clarity over the balance of ambition between managing allowances for compliance purposes and managing for trading profits will be vital for companies.

Irrespective of trading ambitions, however, most utility companies will need to participate in the market, either to purchase emissions allowances in cases where they foresee shortfalls in planned abatement or, less typically, where they expect to exceed target emissions. Critical questions face utility companies. Do they have a clear assessment of the market that will guide buy and sell decisions? Should they risk entering the market early, despite uncertainty about final market shape and rules, or wait in the hope of a long market developing and risk price spikes? How far should they use derivatives and engage in arbitrage?

Companies will need to manage both a compliance function and a trading function. These will need to be kept separate from a risk management perspective, but they will also need to work in synergy. Smaller companies may wish to outsource the trading activity to external, specialist traders or to develop this capability in partnership with others. These options may help access the necessary skills and expertise, but they also raise new governance and risk management issues, which will need to be addressed.

Companies will also need to ensure that they establish rigorous emissions trading procedures.

Seize the initiative

Emissions trading has immediate and important implications for utility companies. Effective strategies that make the connection between emissions trading and value will be vital. In turn, companies need to be ready to communicate these compellingly to capital markets that are becoming increasingly aware of climate change risks generally, as well as specific emissions trading risks. Clarity on overall strategy needs to be matched and integrated with effective and robust systems to optimise trading, tax, legal and special project needs and opportunities.

There is no single, standard solution. Individual companies will face different challenges. But there is both a common imperative and a common opportunity. The imperative of managing the process to enhance and protect value for shareholders is particularly immediate in Europe as emissions trading legislation takes hold. The wider opportunity is for companies to set a lead and to gain advantage from the momentum that this could offer. Companies that seize the initiative will be well placed in a business context that will become increasingly dynamic, with the interplay of consumer, regulatory and capital markets forces presenting new challenges and opportunities worldwide.

You can obtain copies of the* Global Utilities Insight *2004 report from* **www.pwc.com/energy

Dear Reader,
Please note that *Energy Network* will be taking a summer break and will not be mailed out with your August issue. The next issue will appear in September, however the July issue of *Energy Network* is double the size.

Towards Zero Carbon: Sustainability in Practice

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

Tuesday 21 September 2004

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

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

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

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

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

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

Speakers include:

- Dr Tony Day – London South Bank University
- Joan MacNaughton – DTI (invited)
- David Olivier – Energy Advisory Services
- Professor Sue Roaf – Oxford Brookes University
- Sam Heath – London Renewables
- William Orchard – William Orchard & Partners
- Dr Nick Banks – SEA/RENUE
- Louise Kingham – Energy Institute
- Dr Patrick Devine-Wright – De Montfort University
- Gordon Taylor – Independent Consultant


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Tickets:
Member: £150.00 + VAT
Non-Member: £225.00 + VAT

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The EU emissions trading scheme – friend or foe?

Over the past six months there has been growing debate about the merits and short-comings of the European Union's emissions trading scheme (EU-ETS) initiative to combat climate change. *Edward Hopcroft*, Strategy Director of LogicaCMG's UK Energy & Utilities business, takes a closer look at the issues of concern and argues that there is a real chance for companies to benefit from the scheme through effective emissions management and the trading of allowances.

LogicaCMG recently undertook a study of British industry attitudes towards the EU-ETS initiative. The findings suggest that companies are experiencing a range of emotions, including concern that the scheme could be costly to implement and scepticism that it would be profitable for their organisation. At the same time, more than three-quarters of companies surveyed expressed a desire to do as much as possible for the environment.

Levels of knowledge about the scheme are also mixed, with only one-third of businesses claiming to be 'very well informed'. It is likely that this lack of clear information is a big part of the problem.

Ins and outs of the scheme

In 1997, at the Kyoto Summit on Climate Change, the EU signed up to an agreement to reduce greenhouse gas emissions by 8% on 1990 levels by 2008. To honour this agreement the EU decided that the UK would be required to reduce its emissions by 12.5% by 2008. In a move that has angered industry, the UK Government has set itself a target well in excess of this goal; requiring companies to reduce emissions by 15.2% by the year 2010. Although this is a reduction of the government's original pledge to reduce UK emissions by 20%, it is still well in excess of other European countries.

The scheme will work on a 'cap and trade' basis. EU Member State governments are required to set an emission cap for all installations covered by the scheme. Each installation will then be allocated allowances for the particular commitment period in question. In the UK, the National Allocation Plan (NAP) – the number of tradable allowances each installation will receive – was submitted to the European Commission on 30 April. It was published for public consultation from 6 May to 3 June 2004. The European Commission is expected to respond to the UK NAP in September this year. It is then that companies with UK operations will know their individual allowances and whether trading will be a viable option for them.

Trading of emissions

The phrase 'emission trading' is somewhat misleading. It does not refer to the buying and selling of emissions themselves, but rather to the trading of rights to emit greenhouse gases into the atmosphere. In this way, companies will be able to find the most economic way for them to stay within their emissions allowances. For example, if a company has emissions of 1,000 units and assumes a cap of 900 units it can look to buy allowances from somewhere else. In this way, with companies trading within the limits, the overall emission allowances in the UK remain the same and companies can avoid the fines of €40 on every tonne they exceed their limit.

Carbon dioxide (CO_2) trading will impose new financial liabilities, legal obligations and process challenges on businesses. They will have to track their facilities' CO_2 emissions to forecast against targets, evaluate options to cut emissions and relative costs per tonne of CO_2 reduction, and use methods appropriate for their industry, process and fuel to match discharges with allowances. They will then have to decide on whether to buy or sell on the market.

Moreover, businesses will have to manage these activities across multiple sites and activities, reporting data to government bodies or regulators. All of this is a distraction from their core business – and if they get it wrong, there could be serious financial consequences.

Financial benefits

However, there could also be financial *benefits* to trading, about which most UK companies are unaware. With the correct preparation and approach, companies could reap the benefits of the scheme. According to our research only a third of companies in the UK are planning to trade emissions – this is compared to 56% in Spain. One of the reasons behind this is that Spain has been granted more emissions under the scheme. In terms of industry variations

The mother of all environmental scares

Man-Made Global Warming: Unravelling a Dogma. *Hans Labohm, Simon Rozendaal and Dick Thoenes. Multi-Science Publishing, 5 Wates Way, Brentwood, Essex CM15 9TB, UK. ISBN 0 906522 25 0.*

'...Suppose you are Minister of the Environment of a cute compact-sized country, Wonderland, somewhere in Europe. You are a prominent member of the biggest party in the country, the Christian Democrats, and within that party you are a champion of green causes. Yes, they even call you Mr Green. You regard this to be the logical corollary of your Christian faith. You believe God is committed to his creation and that he has delegated the care of it to humans. This is how you translate good stewardship, which is one of the basic tenets of your faith, into practice. In this context you believe that the Kyoto Treaty, which addresses the mother of all environmental scares – man-made global warming – is crucial and should be supported by all means. You have an academic background in public administration, which does not augur too well to understand climatological issues. But you are happy to rely on the backing of experts at your Ministry. Also, you recall that, after all, war is too important to leave to generals. In the same vein, you argue that climate is too important to leave to climatologists....'

The 'Wonderland' described in this book by Hans Labohm of the Netherlands Institute of International Relations, Clingendael; together with Simon Rozendaal, a chemist and science writer; and Dick Thoenes, a chemical engineer, could apply to any EU member country as governments begin their allocation processes for greenhouse gas emissions permits. Adherence to the Kyoto Treaty, which has passed into national law of all EU member states, and the launch next year of the first international emissions trading scheme, places the EU in the forefront of international climate politics.

Self-confessed climate sceptics, Labohm *et al* trace the origins of the man-made global warming paradigm from its conception in 1898 in the imagination of Swedish chemist Svante Arrhenius – who won the Nobel Prize for explaining the electric conductivity of ionic solutions – its politicisation during the Cold War, to counter the influence of Opec or the coal unions, and the government funding of 'Big Science'. They explain the manipulation of data under the notorious 'hockey stick' approach, which has been used to demonstrate a dramatic warming during the late 1990s, to today's obsession in government and industry circles with quantitative modelling ('garbage in, garbage out'), which is used to explain that any given phenomenon is whatever the modeller wants it to be.

The climate debate

Anyone who has struggled to understand the dynamics of non-linear processes in a coupled ocean-atmosphere system, or the causes and consequences of the Permian extinction, tends to take a dim view of the fashionable hypothesis that human activity in the form of fossil fuel burning is creating a catastrophic climate change. But the climate debate has never been about scientific reasoning, or even saving the planet – rather power and money. This is in the gift of government, and is creating a massive corruption of science.

Over the last 15 years in the US annual government funding of climate science has risen from a few million dollars to over \$4mn, and rising. Only governments can fund the huge computer models upon which climate projections are made. If a scientist does not fall in line with the prevailing alarmist ideology, there is no funding. This reality, the authors note, makes a nonsense of the whole concept of 'peer review'. A supranational 'green elite' imposes its terms on the developing world. The implementation and enforcement of the Kyoto Treaty throughout the EU will cost hundreds of billions of euros annually, Labohm says.

Completion of this book coincided with the belated realisation by EU industry of the price it will pay for the EU's political vanity in ratifying Kyoto. In contrast with the US, Canada or Australia, there has never been an EU debate on Kyoto – dissenters have been muzzled by a complicit and ill-informed media, while popular views on Kyoto have been conflated with antipathy towards the Bush administration. Earlier this year as Russian Government officials attacked Kyoto as a potential disaster for Russian economic development, the climate sceptics thought the moment had arrived for a real EU climate debate. The costs of Kyoto were rising up the political agenda ahead of EU legislative elections in June. The authors may have thought they were justified in saying that the number of victims of 'green fundamentalism' – an allusion to the restrictions on economic development this places on the developing world – made the 'mega-terror of Al Qaeda' pale by comparison.

Fighting alarmism

Fighting alarmism with alarmism is never a good idea. The 11 March terrorist attacks in Madrid removed the nascent EU climate debate from the headlines. Hull University's Sonja Boehmer Christiansen, a leading sceptic, says the EU uses the environment to expand its competence, a way to push for EU political integration, and for its version of 'eco-imperialism' worldwide without admitting to it. Labohm thinks that eventually the EU will try to rescue its industry by watering down the terms of its Kyoto obligations in the same manner as it has done with the Growth and Stability Pact. So, Europe's industry will become a conglomeration of over regulated rent-seekers, a vast international bureaucracy secures its pension, and the integrity of science disappears. ●

Maria Kielmas

across Europe, power generators are the most supportive of the idea of trading (see **Table 1**).

So, why are so few companies planning to trade? This is surprising when you consider the financial benefits that can be gained in this way – especially for smaller companies who will not need the full allowances they are given. There are, of course, many possible reasons for this reticence to trade emissions, but I believe the most likely reason is not only ignorance of the scheme itself but also a lack of awareness of the advantages it can deliver when managed correctly.

Impact of ETS

The oil, gas and energy industries are among the most positive about the scheme. Moreover, 78% of oil and gas companies and 70% of power generators across Europe expect the scheme to begin promptly in January 2005, while 100% and 96% respectively intend to fully comply. These sectors also lead the way in terms of preparation for the scheme (see **Table 2**) and are therefore best-placed to save money through adequate IT implementations and to get ahead on the trading market.

There are also concerns over the knock-on impact of the scheme on pricing – especially in the energy sector. It is expected that the emissions

Industry	Percentage
Power generators	33%
Paper & pulp	19%
Iron & steel	13%
Heavy industry	11%
Auto	9%
Cement	7%
Refineries	5%
Total	**16% expect to be active/frequent players in ETS trading**

Table 1: Proportion of business sectors that expect to be active/frequent players in ETS trading

Industry	Percentage
Refineries	91%
Power generators	86%
Iron & steel	78%
Paper & pulp	75%
Cement	66%
Auto	60%
Heavy industry	48%
Total	**74% have started preparations**

Table 2: Proportion of industry sectors that have started to prepare for emissions trading

allowances will continue to drop year on year. If companies incur more costs to comply, who will bear the brunt of these costs? If it is the customers then we will see prices rise even further over the next few years. For example, electricity prices are expected to rise from anything between 4% (the Commission's estimate) to 75% (industry estimate).

According to the UK emissions lobbyist Carbon Trust, the majority of institutional investors are unaware of the impact of the EU-ETS on the value of their portfolios. Nearly half of investors surveyed by Mori for Carbon Trust claimed to know nothing about the scheme, while 54% said they believed climate change regulations posed a considerable commercial threat to UK industry over the next decade. In fact, the ETS is already a driving factor behind the price of electricity. On an almost daily basis prices are rising and falling on the back of newspaper articles on the implementation of the scheme.

The competitiveness of the oil, gas and energy industries is also expected to suffer. In the UK, the government has committed to reducing emissions by 15.2% – more than any other country in Europe. If other countries receive softer reduction targets prices those countries will not be affected as severely as in the UK. This will affect the UK's place in the European oil and gas market and it will encourage non-UK entrants into the domestic market.

Getting more from the ETS

In order to gain any significant benefit from the scheme companies must update their strategies, IT systems and processes to implement effective emissions management. Most companies' current systems and processes were not designed with the ETS in mind and, as a result, they will not be able to efficiently plan for or execute emission reduction compliance programmes.

Third-party companies can be brought in to provide emissions management solutions. Software is tailored to individual needs, helping companies to comply with the EU Directive and, for more progressive companies, with the exploitation of their emissions position. Through the trading scheme outlined earlier, it should be possible for companies to make money. A company bringing emissions under target could earn profits by trading its unused or surplus allowances. Software solutions help organisations keep emissions inventories of their installations, record and settle emissions trades, file reports to regulators or authorities, as well as design, test and optimise abatement strategies. However, only 26% of companies within the UK have cottoned on to this idea, compared to 47% in Spain and 40% in Belgium and Germany.

The EU Directive has added another dimension to an already complex problem of asset and portfolio optimisation. Emissions management software will help companies to fully understand the 'carbon cost' of any trading or asset-scheduling decision, keeping them ahead of the game. Such systems can be fully embedded within an organisation's trading, risk management and asset scheduling systems through integration services.

For smaller organisations that may find buying a software solution expensive, it would be more cost effective to use a service offering a software suite that helps them manage their emissions obligations.

Outlook for the future

Compared to the rest of Europe the UK is lagging behind in terms of preparation for what is a vitally important piece of legislation. Yes, of course there are negative consequences that potentially go hand-in-hand with the scheme, but these can and should be limited with an understanding of what companies have to do to prepare for the scheme and manage their emissions successfully.

Early investment will enable companies to address the challenge and capitalise on compliance, turning the ETS from a foe into a friend. ●

...continued from p2

Colombia's actions appear to be a sensible and rational approach in attempting to reverse production decline and overcome security fears – it is to be hoped for both the country and the companies that the efforts are rewarded by exploration success and greater oil company involvement.

Colombia's approach appears in stark contrast to Indonesia. Production in Indonesia has been in decline since 1991 and in March and April of this year it become a net importer of oil. Current production is 970,000 b/d of oil, with the expectation of further falls. The country has failed to incentivise exploration and continues with some of the most onerous fiscal terms of any major oil producer. It seems very strange that a country that must be desperate to maintain exports for revenue and to remain an Opec member apparently cannot even agree terms with ExxonMobil to develop the 600–1,000mn barrels of known reserves in the Cepu block (Banyu Urip).

continued on p36...

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Speeding approval for gas-to-market technologies

As an alternative to LNG technology, CNG offers economically viable and competitive methods of rapidly monetising natural gas in short-haul trades or certain geographic locations, according to *William J Sember*, ABS Vice President of Energy Development. In recognition of this, ABS recently published new guidance notes* for building and classing ships carrying CNG, that will facilitate CNG industry development by providing a comprehensive framework of reference material while identifying acceptable methodologies for achieving class society approval of new CNG technologies.

Figure 1: Map showing regions where CNG may offer a transportation alternative to the start-up costs of new LNG trade routes. Market and technical studies indicate the viability of CNG transport when the one-way distance is 2,500 miles or less. When compared with LNG and GTL, CNG project advantages include low-market entry-cost thresholds and economic benefits from less gas lost in processing.

Relatively long distances between the gas sources and markets, or difficulties associated with accessing remote, deepwater offshore fields, may make pipelines prohibitively expensive for otherwise promising gas projects. Because many worldwide gas-producing fields lack suitable infrastructure for liquefying natural gas, and because terminal regasification facilities may be similarly limited, transportation of this 'stranded' gas in compressed rather than liquid form offers cost and operational benefits. (See **Figure 1**.)

For example, gas can be loaded directly on to newly designed gas carriers from offshore production facilities, increasing safety and decreasing security concerns. The gas can be compressed and contained onboard, eliminating the need for costly liquefaction and re-gasification processing. In some designs, CNG carriers also can discharge gas directly into terminal facilities located offshore, further minimising potential impact to population centres and areas of high environmental sensitivity.

These operational benefits are indicative of the potential for CNG market growth as new technological milestones are reached, and ABS is helping industry stay ahead of the curve by defining criteria for the technology validation process. The CNG guide – entitled *Guidance Notes for Building and Classing Ships Carrying Compressed Natural Gas* – builds upon the International Gas Code (IGC) of the International Maritime Organisation (IMO) as a platform of regulatory standards accepted by the international marine community.

However, progressive and novel concepts in CNG may require new directives.

Call for guidance

Operators and developers have been calling upon ABS to provide more risk-based classification guidance than ever before. CNG technical advancements call for more application of risk-based risk assessment because the traditional codes and inspection rules don't apply. For example, the present IGC covers the transport of methane as a liquid, but the ABS guide covers the transport of methane as a gas. While LNG is transported at atmospheric pressure (1 bar), CNG is transported at elevated pressures of 150 to 250 bars. Furthermore, LNG is always at a cryogenic temperature of –163°C, but compressed gas will range from an ambient temperature of 30°C to 40°C down to between –30°C and –40°C. Therefore, the design basis and the construction materials for CNG containment systems must differ from those outlined by the IGC.

The IGC specifies four different containment systems for natural gas: membrane tank, type A tank, type B tank and pressure tank. Existing pressure tanks generally utilise one pressure container per tank, but current novel containment concepts have multiple pressurised containers per tank. In addition, the required inspections of the large number of containment systems, both at fabrication and in service, pose problems if only the present inspection guidelines of the IGC are used.

To achieve optimum balance of temperature and pressure, the ABS guide assists designers in satisfying and building upon the design criteria of the IGC and the American Petroleum Institute (API). Inspection plans for the large number of pressure containers also are addressed in the new guide.

Approval in principle

The guide addresses the development of novel ship and containment designs with the goal of achieving ABS approval in principle (AIP), a fast-track alternative to prescriptive classification rules and the first step in the regulatory and vessel certification process.

First applied to short hauls of small gas volumes, these developing concepts now promise a new generation of CNG solutions. Recent examples include the TransCanada proposal for a gas transport module (GTM), based upon the company's composite reinforced pipeline (CRLP), see **Figure 2**. The concept initially concentrates on developing smaller vessels and barges for river application.

An alternative to conventional pressure systems is the 'Coselle' vessel design, approved in principle by ABS and developed by Cran & Stenning of Calgary, Alberta, Canada. The Coselle containment system uses small diameter pipe in coiled cylinders for longer periods of sea transport. (See **Figure 3**.)

Meanwhile, Trans Ocean Gas proposes a unique method of CNG transportation utilising composite pressure vessels in the hold of a ship. The fibre-reinforced plastic (FRP) pressure vessel gas containment system has applications in the national defence, aerospace and natural gas vehicle industries. The FRP gas containment system employs

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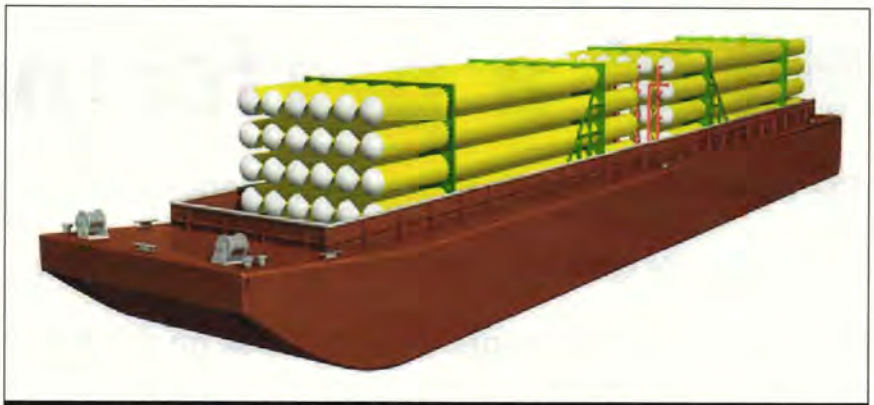

Figure 2: These gas transport modules (GTM) use straight large-diameter pipes to store and transport gas at ambient temperature. The container material is based upon TransCanada's composite reinforced pipeline (CRLP) concept. The design initially concentrates on developing smaller vessels and barges for river application. The capacity of TransCanada's river barge design is 25–80mn cf of gas, with the proposed ocean barge capacity estimated between 50–100mn cf, both at pressures of 3,000 psig.

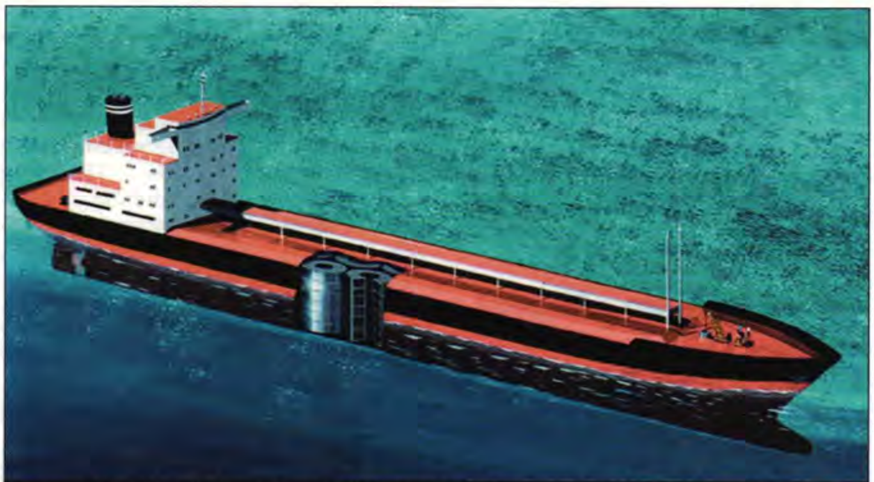

Figure 3: The 'Coselle' containment design received 'approval in principle' from ABS in 1997. Employing this containment system, the ship design has been updated to provide 600mn cf of gas transport capacity.

Figure 4: The EnerSea volume optimized transport and storage (VOTRANS) system delivers gas in long, large-diameter pipes in an insulated cold storage cargo package at low pressures. The design accommodates 700–800mn cf of natural gas, depending on the specific gas composition. EnerSea intends to use this vessel to support economic gas transportation services for applications with average supply rates ranging from 300–500mn cf/d of gas in markets up to 2,500 miles away.

What a performance

The recent appearance of the annual reports of most publicly quoted petroleum companies for the financial year 2003, together with Shell having to substantially downgrade its proven reserves, makes it a timely moment to consider 2003 performance for a range of petroleum companies, writes *David Wood.**

A group of 26 of the larger North American and European publicly quoted petroleum companies have been reviewed for this article, as listed in **Table 1**.[1] The performance measures presented are based upon numbers extracted from the companies' annual financial statements and reserve reports.

Shell's reserve revisions in context

In late April 2004, Shell reported its third reserves downgrade in three months, cutting 4.35bn boe off the year-end 2002 proven reserves and a further 500mn barrels of the year-end 2003 proven reserves. This led to restated proven reserves of 15bn boe at year-end 2002 and 14.5bn boe at year-end 2003, representing a 27% reduction in reserves from the originally quoted proven boe reserves figure for year-end 2002.

In the absence of formal issue of Shell's 2003 annual report at the time of writing (May 2004) its 4Q/full year 2003 financial results (issued on 4 February 2004) and the some 27% downward adjustments to proven reserves, widely reported in the press, have been used to approximate Shell's position in relation to the rest of the 26 companies considered here ('the 26'). **Figure 1** shows the impact of the reserve downgrade relative to the performance of the rest of 'the 26'. Perhaps surprisingly, the reserves downgrade only moves Shell into third place, behind BP, but still some 2.5bn boe ahead of ChevronTexaco.

However, to understand the full significance of Shell's reserves downgrade, composite performance indicators that include reserves should be considered. One of these, reserves to production ratio (R/P) is shown in **Figure 2**. The R/P is a valuable metric because it combines the effect of reserves (measure of long-term resource availability) with production (ability to generate revenue, cash flow and income, today). This ratio really addresses the potential performance capability of an upstream petroleum company in the medium term (ie over a five- to 10-year period). When ranked by this parameter Shell drops from first to 18th place! An R/P of 10.2 years also raises questions about how Shell will be able to sustain current production rates from its drastically reduced reserves base in the medium-term.

Both proven reserves and R/P alone are limited in their ability to reveal all we need to know about current and potential future performance. Proven reserves ignore the potential contribution over the medium- to long-term of other categories of reserves and resources defined at lower levels of confidence (ie probable and possible), which a company must continuously explore for and upgrade through appraisal, to sustain or improve its production performance into the future. A company holding only proven reserves will have production from its depleting resource heading in only one direction – down! Neither reserves nor production factor in oil and gas prices or capital and operating costs, which are integral to the profitability of oil and gas production operations. Hence it is essential to broaden the review to include a number of other financial metrics to get a more balanced view of performance.

Rather than focus this review on Shell's current woes, there is a wealth of interesting comparative performance information to be extracted from the 2003 results for 'the 26'. The questions to be asked are: 'What metrics should the industry be looking at to judge performance?' And, in the light of Shell's disclosures: 'Should all those figures be taken at face value for most of the other companies?'

The second question is beyond the scope of this analysis, but is one the industry and its regulators rapidly need to address in order to restore public and investor confidence. This review takes the figures at face value and focuses on the first question. The answer, not surprisingly, is that proven reserves only provide a part of the story and performance regarding reserves must be judged in conjunction with a range of other metrics.

Company size – the Big League

Size on its own does not tell us much about a company's performance *per se*, but it does provide some insight to the assets and resources available to companies, their ability to compete globally and peer group pecking orders. **Figure 3** plots total assets from the financial reports against proven reserves.

The largest nine companies are clearly distinguished from the rest. ExxonMobil is the largest and, together with BP and Shell, forms the 'Big Three'. These nine companies are the ones that compete for the largest international projects; they have to for materiality reasons in order to have an impact on their growth and performance. The good positive correlation between total assets and proven reserves is encouraging as the two measures are essentially independent of each other.

Contrary to the perception of many, the value of a petroleum company's reserves does not appear on its balance sheets. It is only the costs spent upon them, ie the investments made in developing the fields and building the associated infrastructure, that are measured in balance sheet asset values, and these are depreciated over time subject to generally accepted accounting principles (GAAP). Taking into account the time factor of expenditures and the various stages of the field maturity of producing fields there is no reason why asset values and reserve values should correlate exactly. The positive correlation essentially reflects the fact that large proven reserves generally require large expenditures on facilities (assets) to bring them into production.

26 Petroleum Companies Selected For 2003 Year-end Performance Comparison	
Amerada Hess	Husky
Anadarko	Hydro
Apache	Kerr McGee
BG	Marathon
BP	Nexen
Burlington	Occidental
ChevronTexaco	PetroCanada
ConocoPhillips	RepsolYPF
Devon	Shell (RD)
EnCana	Statoil
ENI	Talisman
EOG	Total
ExxonMobil	Unocal

David Wood & Associates

Table 1: Companies selected for comparison

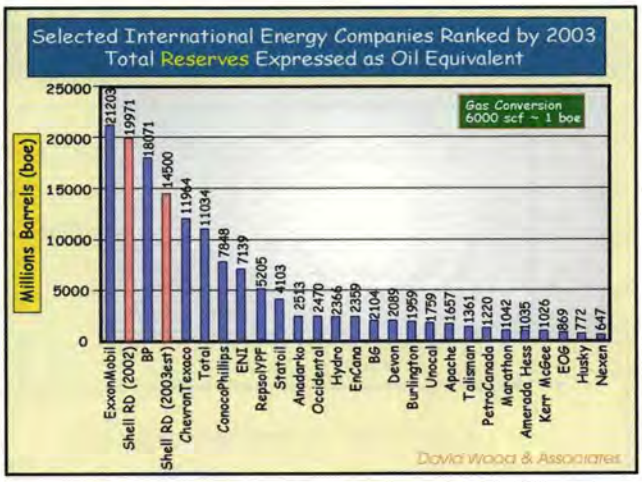

Figure 1: Proven reserves for 'the 26'

The problem with both of these measures is that they are not only historical but also incomplete – total assets tells us something about what has been spent, but not what needs to be spent; while proven reserves tells us nothing about other reserves categories.

The standard measure cash flow forecasts required by the Securities and Exchange Commissions of the US and Canada as part of the annual financial statement submissions goes some way to addressing the former issue, using a range of proscriptive assumptions on product prices and discount rates. What companies are obliged to quote, and have independently audited, by way of other categories of reserves being appraised, and what is being spent upon that appraisal and development currently leaves much to be desired.

Current performance

Comparing annual production (boe) and net income provides insight to how a company has performed in a recently completed reporting period (**Figure 4**). Of course, high oil and gas prices have made 2003 a high performance year in net income terms for most of 'the 26'. The largest nine companies again are clearly distinguished from the rest. ExxonMobil is the best performer and, on this basis, with Shell remaining second in the pecking order. Longer-term reserves issues seem only to have slightly impacted Shell's current performance in 2003 (although its production volumes did shrink by some 2% from 2002, see **Figure 5**).

ExxonMobil lies above the trend defined by the other companies. This is probably a consequence of a larger portion of its assets than other petroleum companies being associated with its downstream and chemicals divisions, which are independent of upstream production. On this assessment, a case can be made for sub-dividing the 26 companies into three groups: the 'Big Five'; the 'Middle Four' (Eni, ConocoPhillips, Statoil and RepsolYPF); and the rest.

Reserves replacement and production growth

Figures 3 and **4** demonstrate that there are clear relationships between reserves and production and balance sheet and profit and loss financial indicators. In seeking indicative short-term performance measures linked to the underlying assets of petroleum companies it is particularly useful to comparing growth in production and the ability to replace the reserves a company has produced over a specific period. **Figure 5** plots these two metrics for 'the 26' in terms of their reported 2003 results.

Production growth must be matched by reserves growth, if not the ability of a company to sustain growth diminishes. The quadrant sub-divisions are useful for benchmarking and identifying future strategic issues for specific companies. Clearly the best performers in 2003 are located in the northeast quadrant (eg Devon, Apache and EnCana) and the worst performers in the southwest

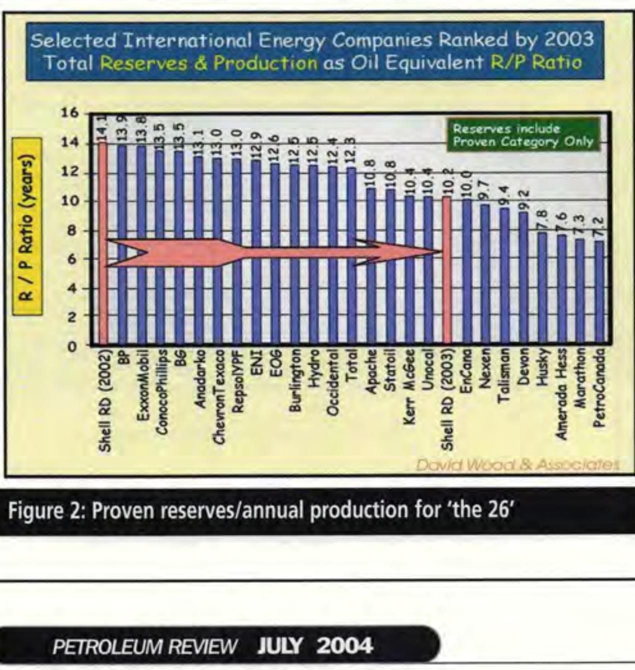

Figure 2: Proven reserves/annual production for 'the 26'

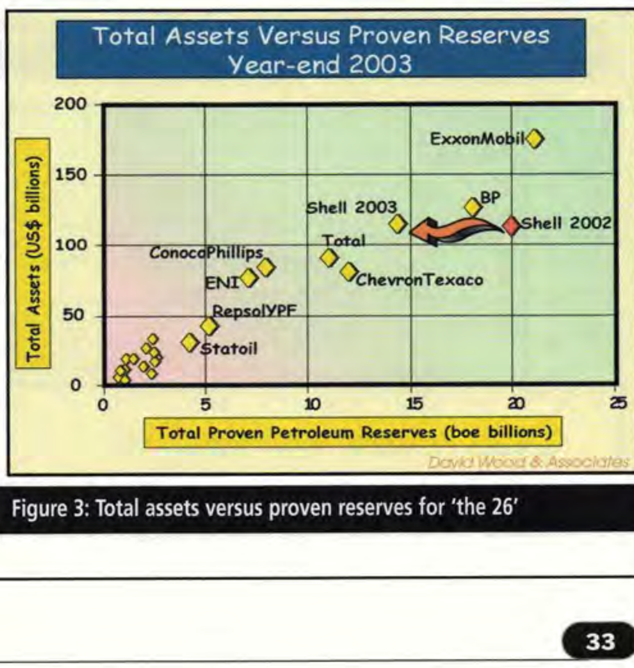

Figure 3: Total assets versus proven reserves for 'the 26'

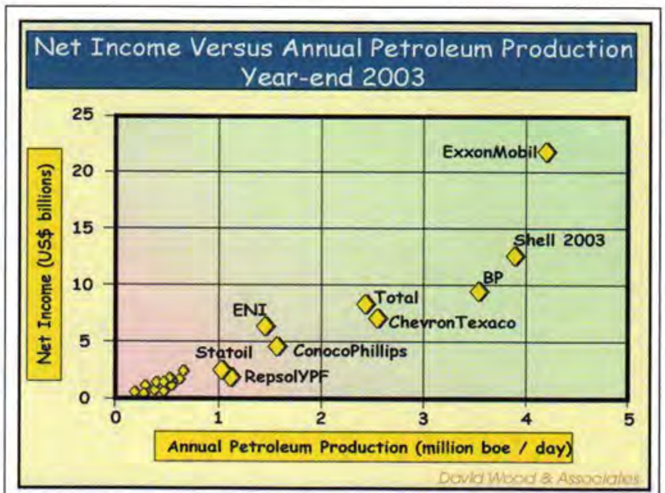

Figure 4: Net Income (earnings) versus annual production (in boe) for 'the 26'

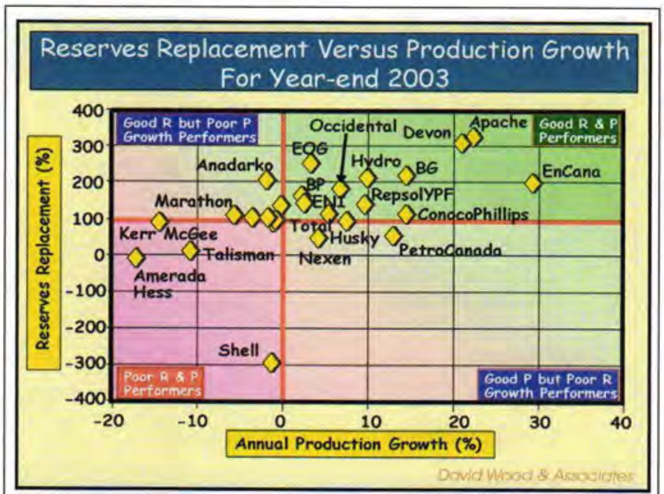

Figure 5: Reserves replacement versus annual production growth for 'the 26'

quadrant (eg Shell, Amerada Hess, Talisman, Kerr-McGee). Companies located in the southeast quadrant appear to be poor explorers or acquirers of reserves but efficient producers of the proven reserves they hold (eg PetroCanada and Nexen), or perhaps they have large quantities of probable reserves not considered? Companies located in the northwest quadrant appear to be good explorers or acquirers of reserves, but inefficient producers of the proven reserves they hold (eg Anadarko and Marathon), or perhaps they have made recent discoveries that are under development/appraisal, but yet to come onstream?

It is the independents that usually dominate the outer reaches of this graph. The materially larger size of the reserve and production base for the Big Five companies makes it harder for them to move substantially in any direction away from the quadrant intersection during a single year. Shell has certainly managed this, negatively, for 2003! The plot also highlights the 2% drop that Shell recorded in boe production in 2003 versus 2002.

A word of caution about interpreting such diagrams without more detailed analysis – single year figures can provide an unrepresentative snapshot of performance (eg Total's relatively low reserves replacement percentage in 2003 conceals the fact that it has recorded substantially higher reserves replacement averaged over the past five years).

Looking at the averages of these metrics over a longer period (eg three to five years) provides more insight to the medium-term performance and the ability of a company to sustain specific growth rates. Also, more detailed plots should, if possible, be constructed to discriminate between reserves found with the bit from those replaced through merger, acquisition and divestment activity. It is useful to discriminate these two sources of reserves to establish a company's exploration capability.

Current indebtedness

Comparing debt to total capitalisation ratio [debt/(debt+equity)] among 'the 26' indicates that gearing varies significantly (<10% to greater than 60%) among the companies. **Figure 6** shows this ratio versus net income and clearly distinguishes ExxonMobil from the rest with its exceptionally low gearing. The Big Five all maintained comparably low debt in 2003.

Low gearing and ability to finance investments from equity funds and cash flow provides companies with greater financing flexibility and stability. It also provides them with strength to weather adverse market conditions should they materialise in the future and to exploit major acquisitions or mergers as and when they materialise. However, financial theory suggests that to maintain gearing at too low a level means that a company is not leveraging its assets to their full potential (or does not need to in order to satisfy share-

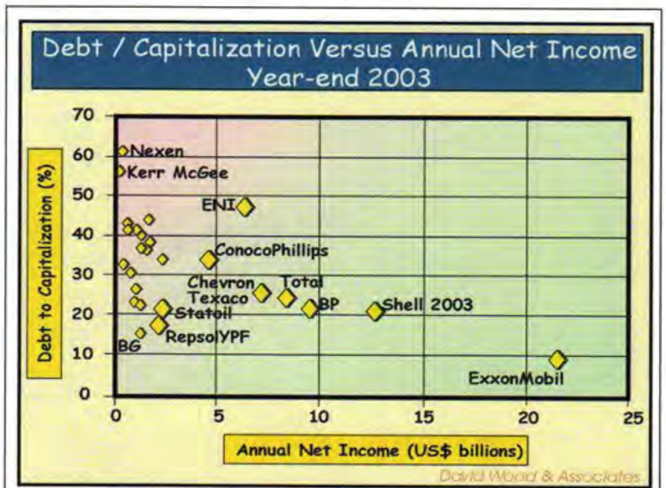

Figure 6: Debt/capitalisation versus net income (earnings) for 'the 26'

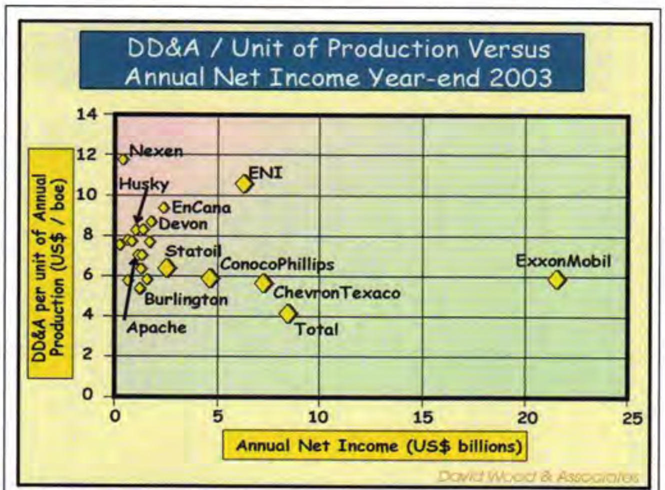

Figure 7: DD&A versus annual production (boe) for 20 of 'the 26'

holders' expectations?). In any event, the 2003 story on petroleum company indebtedness suggests that lenders' best customers come from the independent petroleum companies.

If Shell had been highly geared the credit rating downgrade that has resulted as a consequence of its repeated reserves downgrades so far in 2004 would undoubtedly have had more significant financial repercussions for the company than has so far been the case.

Cost performance

An important part of company performance assessment that has yet to be addressed in this review is that associated with cost. How efficiently are these companies investing capital (capex) and controlling the costs of production (opex) in terms of their reserves and production volumes?

It is much more difficult to extract detailed cost information from annual reports that can be compared on a like-for-like basis. Companies quote a range of different measures and define them slightly differently. A meaningful cost performance comparison would require more detailed analysis and additional information from many of the companies to that provided in their annual reports and is beyond the scope of this review of those annual reports. Several analysts provide reports benchmarking petroleum company cost performance,[2] but they are only as good as the cost breakdowns made available to them by the companies in addition to that provided in their financial statements.

Popular measures of capex performance are finding costs, finding and development (F&D) costs and reserves replacement costs. F&D costs are commonly defined as oil and gas exploration and development capital expenditures divided by total proved reserves additions (finding costs exclude the development capital). Both finding and F&D measures should exclude or distinguish acquisitions costs and divestment incomes, but some companies omit to do this in figures they quote. Reserves replacement costs by definition include acquisitions and divestments.

There are problems with such cost benchmarks. For example, costs incurred in one year may lead to reserve adjustments in later years, and field developments commonly extend over several years with proven reserves allocated to a developing field tending to increase as more step-out development wells are drilled. Looking at costs from a single reporting period is therefore likely to provide an unrealistic snapshot of capex performance. Studies that look at three or more years provide more meaningful insights. A PFC study showed that for the industry finding costs averaged over the 2000 to 2002 period ranged from $0.8/boe to $5.3/boe; F&D costs averaged over the same period ranged from $3.7/boe to $11.3/boe, and; reserve replacement costs averaged over the same period ranged from $2/boe to $7.4/boe.

A useful figure to extract from financial statements prepared in accordance with US GAAP is the depletion, depreciation and amortisation (DD&A) expense reported on the income statement. DD&A is generally calculated on a unit of production basis (ie proportion of production in the year relative to remaining proven reserves) and addresses the amount of the book value of the companies assets (most of which for E&P companies is associated with field development costs accumulated historically, not just in the reporting period) to be offset against income during the reporting period. It is an extremely useful indicator as it brings together both elements of the R/P ratio with costs and itself directly influences (as a deduction) net income.

If DD&A is divided by the annual production (boe) achieved by a company it provides a useful indicator of how efficiently the capex invested by the company has been translated into production in the recent past. High DD&A/boe can indicate at least four possibilities:

- capital costs have been high in terms of reserves proven;
- capital costs have been high in terms of production so far achieved from reserves recently discovered or still under development and yet to fully enter the proven category;
- reserves potential from cumulative field developments have not achieved budget expectations based upon industry reserve replacement cost standards or reserve write downs have been required (eg Nexen, Shell);
- a company has paid too-high an acquisition price for the reserves and production acquired.

More information is required to establish which of these applies to specific cases. Companies with high DD&A charges commonly suggest that possibility number two is the reason and all will be rectified when field developments mature – this is rarely the full story.

Figure 7 shows DD&A/boe of production versus annual 2003 production (boe) for 21 of the 26 companies reviewed for which DD&A figures were readily available in their annual statements.[3]

DD&A of $6/boe, or less, is an industry benchmark that has been achieved by the larger companies. DD&A performance in 2003 by Total and Burlington certainly outperform their peer groups. Lower DD&A was one of the reasons why in 2003 Total had less production (boe) but higher net income than ChevronTexaco. A drastic reduction in proven reserve base, such as that incurred by Shell in 2003, would significantly increase the DD&A/boe charge. DD&A is a metric worth monitoring over several years to judge how capital-efficient are a company's efforts in translating its reserve base into production.

Devon, EnCana, Eni, Husky, Marathon and Nexen all, for various reasons, incurred DD&A charges of greater than $8/boe in 2003. It is noteworthy that Devon and EnCana are star performers on a reserves replacement/production growth basis (**Figure 5**), but have incurred high DD&A charges in achieving that growth. (Apache, another star performer, also has a relatively high DD&A charge of $7.04/boe.) Cost performance of these companies requires scrutiny in future periods to judge their capital efficiency. Indeed, a useful addition to annual statements would be an obligatory five-year history and three-year rolling average of DD&A $/boe of production, with explanatory notes to explain good and poor performance.

A considerable amount of strategic information, including detailed objectives, goals and targets, is provided in the annual statements of most companies. This can usually provide explanations of where and why a company is focusing its capital expenditures and to the level of development maturity of its key assets. It is important to add this strategic analysis dimension to performance comparison and benchmarking studies if they are to be made use of in a learning/decision-making context.[4]

Another aspect to cost performance, not addressed by DD&A, F&D, etc is operating costs (opex), ie all the costs incurred in producing, processing, transporting and marketing the petroleum produced. It is even more difficult to extract meaningful comparable numbers from annual statements for opex than capex, as different companies define such costs differently and selectively exclude various components from the figures they quote in their own strategic analysis.

Terms frequently used, but variously defined are lifting costs, production costs, cost of supply and operating costs. These are extracted from the cost of goods sold (expenses) section of the profit and loss (income) statement, but depending upon the provider may or may not include various elements of overhead, third-party tariffs and other costs that should be included to provide an overall cost of operation.

A detailed benchmarking study is required to provide more meaningful opex comparisons for 'the 26' than can be readily extracted from their annual reports. Many of the larger companies claim in strategic reviews to be operating cost leaders, but often present figures that fail to fully integrate appropriate overhead costs. This is an area where more reporting transparency and standardisation is required if performance comparisons are to be readily possible from annual statements.

Conclusions

Reserves, production, costs and depreciation (DD&A) provide a more fundamental insight to the medium-term performance of upstream petroleum companies than net income from the profit and loss statement or growth in balance sheet assets.

All of these variables, including debt/capitalisation and a company's stated strategies and goals, need to be taken into consideration when attempting to benchmark or explain a company's performance or forecast its future potential or direction.

Notes

1. It would be useful to also compare performance of publicly quoted Russian and Chinese companies (Lukoil, Yukos, PetroChina), but their annual reports were not available at the time of writing. In previous years the large reserves held by these companies have been significantly higher than their associated net income, production and asset values when compared to western petroleum companies. This reflects their lower relative investment on reserves development.
2. For example, Wood Mackenzie and PFC market reports that include cost benchmarking.
3. Detailed DD&A information can usually be extracted from annual 20-F or 10-K compliance reports for those companies with stock exchange listings in the US that are required to submit such reports to the US Securities and Exchange Commission (SEC).
4. David Wood and Associates combine such strategic portfolio information together with performance benchmarking for training and consulting purposes.

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... continued from p31

modular cassettes for ease of fabrication and installation. ABS awarded approval in principle to the Trans Ocean Gas concept in September 2003.

Further along in commercial application is the VOTRANS (volume optimised transport storage) concept of EnerSea Transport, Hyundai Heavy Industries and Kawasaki Kisen Kiasha (see **Figure 4**). ABS awarded approval in principle in April 2003 for this design, which employs 2,400 modular bottles, racked vertically about six inches apart, each 42 inches in diameter. EnerSea's capabilities will allow it to serve gas development projects with rates from 100–600mn cf/d of gas and to connect gas supplies to markets from less than 200 to more than 3,000 miles away.

ABS requirements

Underlying the approval and classification process, ABS risk studies identify the hazards posed by CNG loading procedures and other ship operation parameters. In assessing these procedures and parameters, the guide conforms to API codes for system safeguards:

- gas depressurisation arrangements,
- piping and electrical systems,
- gas dispersion,
- radiant heat levels, and
- fire protection.

In addition, the guide applies existing IGC standards for:

- stability,
- vessel arrangements,
- hazardous areas,
- containment system, and
- fire protection.

The guide places particular emphasis on allowable alternatives in ship design when considering load limitations and stress intensities. At present, there are no existing CNG carriers, so no prior in-service or comparable design review history exists. The new ABS guidance notes will help operators enter and work this burgeoning market by providing its experience in validating novel ship and gas containment designs.

This process consists of three stages as detailed in the new ABS guidance notes:

- *Concept development* – in the earliest stage of development, an operator may ask ABS to assess the concept in terms of possible class approval. This preliminary assessment is referred to as 'approval in principle' or AIP.
- *Approval for classification* – a design that passes AIP would then be subjected to detailed engineering analyses followed by class survey of construction.
- *Maintenance of class* – periodic surveys will take place to validate the renewal of a class certificate.

Final criteria for CNG transport

The experience of TransCanada, Trans Ocean, EnerSea and others suggests that CNG has the potential to fill a large niche in the gas industry, accessing and monetising resources located beyond the economic reach of pipelines and with reserves smaller than the typical thresholds for LNG projects. Before previously stranded gas can be transported, however, flag states signatory to IGC require provision for regulatory equivalents. Coastal states and local authorities at load and discharge must approve safety factors.

Communication among all involved parties – including concept developers, system designers, materials manufacturers, shipyards, operators, regulatory bodies, export and import states – can be coordinated by ABS.

Historically, regulation generally follows after innovation. However, in this instance, development of rules and standards are taking place in partnership with a class society – allowing for innovation and the incorporation of new risk methodologies. The new ABS guide assists with a probabilistic approach to identifying hazards, determining departures from existing codes, providing equivalents and evaluating safeguards.

*The ABS Guidance Notes for Building and Classing Ships Carrying Compressed Natural Gas *are available on the ABS website –* **www.eagle.org** *– under the 'Rules and Guides' section.*

...continued from p28

Meanwhile, the only positive thing to be said about Iraq oil at the moment is that with all exports at a halt it can hardly get worse. Strangely, although the end-June handover is unlikely to solve all of Iraq's problems, it may improve oil supplies. At present, blowing up pipelines can be portrayed as 'denying the invader resources' – after 30 June it will be 'denying the Iraqi's resources'. They may be fighting over who controls the resources, but paradoxically, they may tacitly agree not to destroy the target of their ambitions.

Chris Skrebowski

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

OTC 2004 – The best yet?

***Lawrence Slade*, Business Development and Technical Director at the Energy Institute (EI), provides a brief overview of the recent OTC show and outlines the EI's activities during the event – including the launch of our new EI Houston Branch.**

Lawrence Slade (left) presents an EI Certificate of Appreciation to Iain Murray to thank him for his support in setting up the EI Houston Branch

The annual Houston-based Offshore Technology Conference (OTC) started slightly earlier this year for those associated with the Energy Institute (EI). On the Thursday before the show a reception was hosted by the British Consul General, Iain Murray, to mark the launch of the EI's new Houston Branch. The packed reception also illustrated the close links between Houston and Aberdeen, with a number of the EI's Aberdeen-based members also being in attendance, together with John Reynolds, Aberdeen's Lord Provost. Brian Morr of Technosphere, the Houston Branch's Chairman, commented that he hoped this would be the 'first of many such events' to come for the new EI Branch.

The EI also took this opportunity to present Iain Murray, who will be retiring from his post later this summer, with an Honorary Fellowship of the Energy Institute in recognition of his significant contribution to, and support of, British businesses.

Innovation without limits

The theme of this year's OTC was 'Innovation without Limits'. The event was supported by over 250 well-attended major conference sessions – indeed, many attendees could only find standing room available at several of the LNG-themed sessions such were their popularity.

The session looking at the 'LNG Value Chain' was particularly interesting – both in terms of highlighting the massive investment required both upstream and downstream, with figures of $50bn being openly considered, and also the inexperience in the market, with 42 companies actively looking at projects, of which only 14 have true LNG experience. Key statements from the panel included, from Bill Bullock, General Manager ConocoPhillips: 'Over the next 10 years, capacity will be increased by the same amount as over the last 40 years'. While Doug Rotenberg, President Global LNG BP Gas Power and Renewables, perhaps not surprisingly, forecast volatile prices for the next six years against an increasingly global market as opposed to local regionalised markets. Possibly the quote of the week from the panel, however, was courtesy of President Roosevelt in 1942: 'I wish you would get your guys to look at using natural gas.'

Dose of confidence

The whole of the 2004 event seemed to indicate that a welcome dose of confidence had found its way through the industry. This view is supported by the record attendance figures, with over 50,000 delegates – a figure not met since 1985. It was also a record year for exhibitors, with an additional 200 companies finding their way to Houston, making a total of over 2,100 exhibiting companies. But OTC is definitely not just a domestic event. More than 600 of the exhibitors were from overseas, with the UK, for example, having a very strong presence at the event, with over 90 exhibiting companies present. In all, this year's OTC attracted visitors from 110 countries and exhibitors from 30.

In fact, the UK probably had the largest presence of any country outside of the US. As such it was ably supported by Stephen Timms MP, UK Energy Minister. Speaking at the topical Luncheon, entitled 'Opportunities for Investment in the North Sea', Timms took the opportunity to put the UK's case and, in particular, that of the remaining reserves in the UK sector of the North Sea for future investment. He focused in particular on the new 'Frontier' licences and the encouraging responses to the current North Sea Licensing round, highlighting the pleasing number of new entrants such as Endeavour Energy and independent companies entering the fray.

The importance of Houston to the UKCS and to UK companies was reinforced by Aberdeen-headquartered Cromar, designer and manufacturer of wellservice equipment. Business Development Director, Colin Black MEI, commented that: 'Cromar's key differentiator is the way they engineer innovation in well service equipment. OTC is the perfect launch pad for new technologies and establishing key operational problem areas that can be addressed by changes in well service equipment. The global market is changing and challenging the norm, and any new technologies require support from key decision makers. Although the equipment may actually be used in many international locations, OTC is still where many changes are approved. Launching our first patented tool, the LBO™ Quick Connector received significant interest and is due for full release to the global market shortly. Our patented VariBall™ and VariTool™ are due for launch at the Calgary-based Global Petroleum Show.' Black's view was supported his Chairman Fred Mckay, who said: 'This was our best OTC ever.'

A lot to live up to

In all, this year's OTC proved itself again to be the world's biggest E&P event. Certainly there were concerns about the depletion of resources, and many views on the various scenarios from eminent speakers such as Matt Simmons and Bob Williams of the *Oil and Gas Journal*. But the overall feeling was a determination to continue harnessing new technologies and new methodologies to maximise remaining reserves.

OTC in 2005 has the theme of 'A Sea of Resources: An Ocean of Knowledge'. Judging by 2004, it will have a lot to live up to.

The Energy Institute – one year on

Twelve months ago *Petroleum Review* asked *Louise Kingham* (above), then Chief Executive Designate of the proposed new Energy Institute (EI), what her view from the top looked like as she and a team of members and staff began to implement plans to create the EI. As the EI reaches its first anniversary we asked Louise, now Chief Executive, to reflect on progress to date.

Q. The Energy Institute was created a year ago, on 1 July 2003. A year on from then, how do you feel the process of merging two long-standing organisations has gone, and how much is left to do?

A. In short, it has gone very well. The members and staff have done an incredible job so far. Mergers between membership organisations are renowned for their complexity and the length of time they take to complete – several years in many instances. From the point at which members determined the future – when votes had been counted at the beginning of February 2003 – to creating the EI as a legal entity, only five months were allowed to elapse.

During that time a shadow Council emerged, together with 13 temporary task groups comprising members and staff working together on issues from future strategy and governance systems through to membership services and integrating branch structures. All of these groups had either concluded their planning, ready for implementation by 1 July, or based on the activity, by the end of the summer of 2003. From that point to the end of 2003, only a further six months, we worked to implement the outcomes from these groups. Some became obvious (and operational) instantly on 1 July. For example, implementing effective governance and membership structures, together with rebranding a large amount of material. Others, such as integration and development of a new branch structure – led by members active in the pre-existing networks – has required more time, quite rightly, to organise.

However, my interpretation of how the process has gone not only comes from my personal review of performance but, most importantly, from how those we exist to support view it. Members, both individual and those representing organisations; potential members; and partners in learning, business and government circles have all, at some point in the past year, given me a view of how they feel as witnesses to major change. So far, amongst an exceptionally positive reply, fewer than a dozen individuals have alerted me to further changes they would like to see or simply admit that they remain to be convinced.

We intend to canvass wider opinion more formally later this year, as peoples' perceptions and experiences are what tells me whether we are on the right track. Yes, there is still much to do – most of which is in further consultation with groups of members and potential members as activities that are linked to new service development. These include establishing demand for special interest networks, the future format of key publications and future career development services – all of which will be determined by research in coming months. Beyond that, significantly extending our reach across all activities keeps us focused on the longer term.

Q. To what degree has the organisation 'gelled' into a cohesive whole, and to what degree has it been necessary to keep it as two different organisations? How do you see this developing as we go forward?

A. At the planning stage Trustees from both predecessor Institutes locked themselves in a room only to emerge once key elements around the EI's purpose, aims and vision had been agreed. By doing this at the beginning we were always likely to design a new Institute fit for purpose, rather than simply trying to stitch, somewhat untidily, the two predecessor organisations together.

It might sound an obvious order of things, but many mergers fail and I believe one key reason is that unless you agree at the very beginning about what you are creating, you will be unlikely to concur about the end result! It was at this very early stage that we thought hard about the differences there would inevitably be among the membership and agreed that there was no need to try and blur any distinctions. Rather, these distinctions, often represented through differing views on issues, are what makes an Institute, as the facilitator of debate, a lively and thriving organisation.

Forming policies on issues, however, can be more of a challenge – one that we are working on right now. Essentially, we made a commitment in the merger prospectus to maintain depth and breadth of subject matter, so ensuring this is our priority.

As far as 'gelling into a cohesive whole' is concerned, what I can tell you is that when I visit branches or attend functions members seem to be getting on well – but any more insight would need to come from them! The staff, too, are best placed to tell you if they now feel part of a whole organisation. For the team as a whole, it has been an unsettling year, for obvious reasons. But I think that their achievements collectively, not least relating to the EI's positive financial performance in 2003, tells me that they are settling into their new organisation pretty well and as quickly as can be expected.

Two different organisations have never been, and are not, part of the plan. Building the capacity of one diverse organisation, with a wide range of interests and the capability to home in on any particular energy topic, is how I see the EI developing.

Q. How is the EI now being organised internally? Has the process of merging business systems been completed, and has there been any movement away from the organisation being overseen by, and reporting to, committees of members?

A. The Council of the EI is the governing body, comprising members – just as its predecessor Councils did. The sub-committee structure is different, however, with three mandatory committees of Council: Professional Affairs, Finance and Audit, and Human Resources. In addition to these groups, the technical team works with a members committee known as the Scientific and Technical Advisory Committee (STAC) and the communications team works with a members committee comprising a representative from each EI branch.

It would be fair to say that the members and staff co-exist and, in most cases, our activities would cease if the partnership collapsed. However, the culture is one of working together – not one for another – and that is different to how some other similar organisations operate.

Systems have been integrated and we are just embarking on a project to upgrade some very dated IT systems, specifically to get better functionality and help us to introduce some new services either towards the end of 2004 or early in 2005.

The EI staff team is organised into four directorates. The heads of these groups, together with the Chief Executive, comprise the management team. This group works with the various committees, as do other members of the staff team. However, they also have their own executive responsibilities, targets and challenges to think about and work towards. This can often mean working together with individual members, other contacts in the industry or entire organisations.

Q. Although both were membership-based organisations of energy professionals, there were considerable differences between the old Institutes of Petroleum and Energy. The former served a single, relatively focused petroleum industry and the latter covered a vast area, specialising in facilitating debate on energy policy. How are these different approaches being merged? And how do you see this process going forward?

A. Almost 12 months ago I set out what I believed the purpose of a professional body to be – to bring together a learned community to share knowledge and expertise and, by doing so, collectively we would benefit those individuals involved and ultimately, wider society. The vision, values and future plans for the EI's first few years of operation reaffirmed this position.

On most energy-related issues we will facilitate the debate and encourage members with differing views to develop these and share their knowledge with others – this is how policy develops. On some issues the EI will develop its own voice, as well as facilitate debate, and it will work with groups of members to do so, via Council and a Communications Panel. One example we are working on right now is our concern about skills shortages in the energy industry and how we can work together with other organisations to address the problem. You would expect your Institute to have a voice on this issue, and there will be others topics to address in the future. However, our position on any issue will always be based on sound science and fact. [Members interested in finding out more about being involved in the Communications Panel can get in touch directly with Louise; contact details at the end of this feature.]

Q. How have individual members of the two former organisations reacted to the merger? What are current membership plans and targets?

A. Less than half a dozen members have resigned as a result of the merger. We have received some really helpful and warm communications from members throughout the process, for which I am particularly grateful. Members have driven many of the key elements of the merger, so I believe they have reacted well. However, I am sure, as members are so busy, that I will still bump in to one or two who will ask whether we've merged yet! Our target for this year is to recruit 1,000 new members across all grades of membership.

Q. There are possible tensions between the relatively narrow focus of the petroleum membership and the wider interests of the old Institute of Energy members, many of whom are focused on end-user and sustainability issues. Has this tension been creative or destructive, and how is it being handled both now and for the future?

A. Firstly, I cannot recall seeing evidence in the past 12 months of any tension, although in the early days of an amalgamation there are always sensitivities based on peoples' expectations. Where I have seen differing opinions and views exchanged by learned members, I have also seen patience, understanding and interest – even if disagreement prevails at the end of the discussion! So, I would view that as creative, certainly not destructive.

Both *Petroleum Review* and *Energy World* provide a forum for exchange of views, however wide ranging, as we have seen recent examples of – particularly around viewpoints and letters to the editor. Our events also provide an excellent forum for acknowledging different positions on energy issues – all of which I believe to be healthy and positive. I think most would agree that if we all viewed the world in the same way, life would be much less interesting.

Q. What has been the reaction to the creation of the EI by other organisations – eg government departments, the Engineering Council, other institutions?

A. Very positive. Obviously, the relevant government departments were formally consulted about the creation of the EI and were supportive then, as was the Engineering Council UK. Other institutions have also been generous in making the transition to work collaboratively with the EI as the successor partner to either the former IP or InstE.

Q. You have presided over an enormous agenda for change in the last two years. Are you now looking forward to a period of stability or are there more changes to be made?

A. When you run a mid-sized organisation positioned at the centre of the energy industry, is there such a thing as steady state? I think not. But there is stability in the sense of managing and driving the EI forward whilst recognising the continuous change around us as 'normal' as opposed to generating such huge internal change.

Q. How do you see the EI developing over the next few years and what will be its driving principles?

A. Driving principles over the next few years will be the purpose, vision, values and strategic aims of the EI. There is still much to do in order to be at the forefront of peoples' minds when they think of energy – and that is where I want us to be. A rolling strategic plan and annual operating plans fall out from these driving principles and I have no doubt that the EI will continue to operate in this way, by being very aware of the world around it.

Both the Council and I know we want step changes in several areas of our activities to be more successful for those we exist to support and drive the energy agenda higher in the minds of the public – after all, we exist as a charitable organisation, which means we are about providing public benefit ultimately. I simply urge readers to continue to stay in touch with us and share your thoughts so that step changes we implement to build the capacity of the EI meet with your approval.

If you would like to contact Louise, please e: **lkingham@energyinst.org.uk** *or t: +44 (0)20 7467 7101.*

Refining *profitability?*

Strange things are happening in the refining world. After decades of poor profitability, with margins squeezed between the market's product prices and Opec's crude prices, there are forecasts of sustained healthy margins. Increasing product demand in the US and the rapidly-changing demand slate in Europe are driving the upturn, writes *Martin Quinlan*.*

While world refining capacity was in surplus – as it has been for most of the past 30 years – profits were always under pressure. Refiners were tempted to 'run the marginal barrel', increasing their utilisation rates a little but over-supplying the products market. Because the marginal barrel often ran to a simple hydroskimming yield, it added to the surplus of heavy products. Inadequate product prices increased the pressure to run extra barrels... and so the cycle continued.

Until recently that is. When, early this year, the industry's pricing gurus began to suggest that high product prices were the result of strong refining margins, it was clear that a different set of economic rules had come into play. With demand for refined products bumping up against supply, refining margins were no longer driven by the marginal barrel – they could be fully built-up.

Realistic margins are an encouraging prospect in view of the investment the industry will have to make in coming years. Product quality specifications are becoming relentlessly more demanding in both the US and Europe, while other regions are taking steps in the same direction. Meanwhile, Europe's demand for middle distillates and North America's demand for gasoline are both growing strongly.

On a macro level, statistics for the refining industry's fundamentals do not provide support for the upturn. According to figures for refinery throughputs and capacity given in the *BP Statistical Review of World Energy*, utilisation of primary distillation capacity worldwide in 2002 was only 83%. Even in North America, utilisation was only 90% – hardly suggestive of a shortage – and in Europe (including the former Eastern bloc countries) it was a low 78%.

Micro-factor margin drivers

Driving the upturn in margins, however, are a number of micro-factors. First, the best refining capacity in each region is operating at much higher utilisation rates than the average – which is weighed down by refineries that are either too small, too simple or too old to operate efficiently, or are geographically disadvantaged. Operational statistics given by the major companies indicate that their refining systems are running at virtually full capacity, when maintenance 'turnarounds' are taken into account.

The second factor is imbalances between refined product demand and supply. In Europe, demand for diesel continues to rise strongly as motorists switch from gasoline to diesel engines. New cars tend to be driven for more miles than older ones so, while diesel demand is rising, demand for gasoline is falling steadily. Europe's gasoline demand peaked in 1999 and has fallen year-on-year since then.

The third factor is the fragmentation of the motor fuels market, particularly in the US, but also in Europe. In the US, marketers have to comply with legislation including: the banning (from January this year) of methyl tertiary butyl ether (MBTE) gasoline additive in California, New York and Connecticut; the mandatory blending of ethanol into gasoline in California; the use of reformulated gasoline in certain areas for certain months; and the lowering of allowable sulphur contents in gasoline and diesel.

In Europe, the EU requires 'sulphur-free' gasoline and diesel (with a sulphur content of less than 0.001%) to be made available 'on an appropriately balanced geographical basis' from January 2005, in parallel with the supply of 0.005% sulphur material. However, some markets – such as the UK – are ahead of the game as a result of tax incentives, and are already supplied virtually exclusively with sulphur-free grades.

Markets within markets

Fragmentation creates markets within markets. It also reduces supply, because only the best refineries can comply with latest specifications. Process considerations can also reduce supplies within the refinery, cutting yields. For example, to meet lower motor-fuel sulphur limits, a refiner might have to increase the intensity of hydrotreater operation or increase the hydrotreating cycle time; the result could be a backing-up of streams originally destined for gasoline and diesel, and their eventual diversion elsewhere.

The outcome is premium streams being run into lower-value products. In the case of cracked distillates such as light cycle oil – normally destined for the diesel pool – the alternative is downgrading into the heating oil pool or into fuel oil.

The move to 0.001% sulphur motor fuels has resulted in a loss of flexibility throughout the supply chain, because dedicated tanks and pipelines must be used to avoid contamination with higher-sulphur material. In the refinery, any deviation from specification necessitates the reprocessing of an entire batch of material, because blending-out the off-specification material is not possible. Refineries have also become highly dependent on their hydrogen plants – when few streams can be blended to finished products without hydrotreating, a reduction in hydrogen supply soon forces a cut in crude runs.

All of these considerations constrain supply and can lead to price spikes at times of high demand or when stocks are being built. A look at the background to the main considerations suggests no early solutions – hence the view that margins should remain strong.

Utilisation rates

With capacity in the majors' refining systems being virtually fully-utilised, the obvious solution is for other refineries to increase their throughputs. The problem is that most refineries are already fully-loading their conversion facilities – the catalytic crackers, cokers and hydrocrackers that break down heavy streams into light ones.

Therefore, any increase in distillation throughput runs to a hydroskimming yield, with a large proportion of fuel oil and relatively small amounts of gasoline and diesel. Further investment in conversion facilities is needed to solve the problem, but smaller and remote refineries are generally reluctant to take the risk.

Product imbalances

As noted, Europe's demand for diesel is growing strongly while its demand for gasoline is declining; demand for gasoline in the US is also growing steadily. As reliance on gas increases, motor fuels are forecast to make up a rising proportion of the demand-barrel – because gas mainly replaces heavier products.

However, a counter-trend could be a contribution from gas-derived motor fuels, if substantial volumes of gas-to-liquids capacity are built worldwide.

Further demand for motor fuels will come from industrialisation in China and in other developing countries.

Role of imports

So far, the growth in Europe's demand for diesel has been met substantially by imports – large volumes of gasoil flow in from Russia, the Mediterranean refineries and from the US. Much of this flow (especially the Russian material) is high-sulphur grade, which tends to be used preferentially in the heating oil pool – freeing-up lower-sulphur material for the diesel pool.

But Europe's demand for heating oil is likely to continue its decline, so refiners will need to reinvest to allow high-sulphur gasoil to be utilised in the diesel pool. Yet more hydrodesulphurisation capacity is likely to be needed. More radically, there is likely to be a strengthening case for the construction of hydrocrackers – to break down fuel oil into clean streams for the diesel pool.

For many refiners in Europe, the US deficit of gasoline has been an unexpected bonus. Europe over-invested in catalytic crackers – which produce a high gasoline yield from low-value fuel oil – in the 1980s, and refiners would otherwise be taking large losses on their gasoline production. As it happens, they can supply their surplus to the US at advantageous prices.

The flow across the Atlantic has been growing strongly. US net imports of finished motor gasoline (excluding blending components – another good trade for Europe) averaged 392,000 b/d in 2003, with a gross inward flow of 517,000 b/d offset by exports of 125,000 b/d. Last year's gasoline imports were the highest recorded, and are double the flow of the mid-1990s. Imports rise to a peak in the spring when stocks are being built, reaching 679,000 b/d gross in April last year. Latest statistics show that gross imports of gasoline and blending components ran at 955,000 b/d over the four weeks to mid-May this year.

The Europeans are, of course, at risk from US refiners' moves to increase their gasoline capacity. US gasoline capacity has increased substantially through de-bottlenecking investments over the past decade, but many refineries are now near the limit of economic and technical feasibility for further de-bottlenecking. Additionally, although US refiners have more conversion capacity than anywhere else, they still face the prospect of their yields moving to a hydroskimming configuration at high utilisations.

Specifications threat

Perhaps a greater threat to the trade between the Europe and the US comes from changing product specifications. At present, US specifications permit higher sulphur contents for motor fuels than EU specifications – US gasoline averages 0.03% sulphur and US diesel can contain up to 0.05% sulphur, compared to EU limits of 0.015% for gasoline and 0.035% for diesel. (The EU limit reduces to 0.005% sulphur for both products next January, but many countries have already moved to the 0.005% grade.)

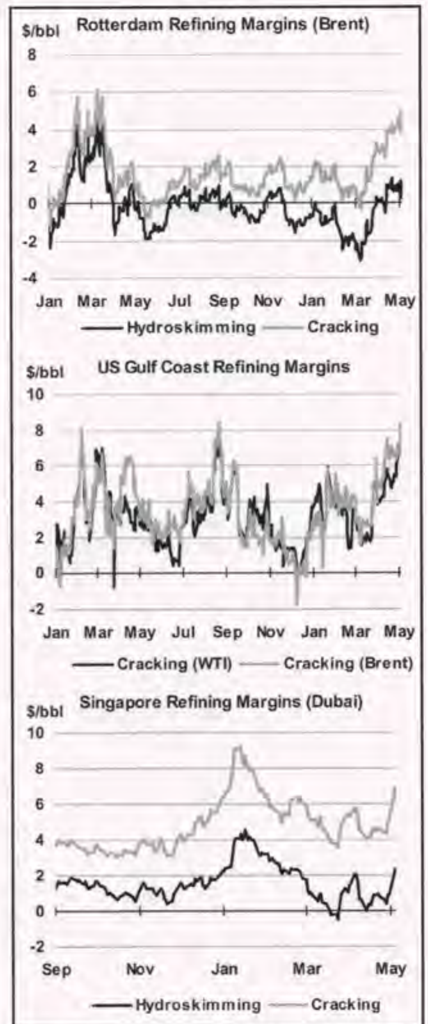
The difference allows European refiners to run their hydrodesulphurisation units at maximum for the European market, and to export higher-sulphur gasoline to the US. Similarly, US refiners are able to produce lower-sulphur diesel for export because they can supply higher-sulphur product to their home market.

Specifications are changing, however. From the beginning of next year the US will require an average sulphur content for gasoline of under 0.003%, and in 2006 US diesel must comply with a sulphur limit of 0.0015%. The EU sulphur limit for both fuels will fall to 0.001% in January 2009 – although, as noted, marketers will be required to make some 0.001% products available from January next year. If the two-way export trade is to continue at existing volumes when very low sulphur limits are introduced, it is clear that a very large increase in hydrodesulphurisation capacity will be needed in both areas.

Investment focus

These trends point to the focus for refinery investment for the next few years. A study into the catalyst market estimated recently that, in the US, $1bn will be spent on clean gasoline and clean diesel facilities over three years – additional to investments already committed. Europe is reckoned to attract investments in diesel hydrodesulphurisation.

Others argue that what Europe really needs is more hydrocracking capacity, to produce large volumes of clean diesel from the area's surplus heavy streams. As hydroskimming margins continue to weaken, profits will migrate to facilities processing more intermediates and less crude, and producing a fuel-oil-free yield. Trade in refinery streams will increase, and advanced refineries will require more and more hydrogen to feed their conversion and product-quality facilities.



Refining margins have risen strongly in 2004. *Source: IEA monthly report*

Options for utilising the heaviest fractions, such as vacuum residue, are becoming more limited in a low-sulphur environment. Depending on crude, the sulphur content of vacuum residue can be as high as 5% – but restrictions on the sulphur content of bunker fuel, its main market, are under discussion in the EU.

Some suggest that the established upgrading options – hydrogen addition processes such as hydrocracking and carbon rejection processes such as delayed coking and residue catalytic cracking – will be joined in a big way by gasification over the coming few years. Vacuum residue gasification gives a nearly-90% yield of syngas, which can be used for electricity generation, chemicals production, or for Fischer Tropsch synthesis of motor fuels.

**Martin Quinlan is an oil industry journalist and a refining economics consultant.*

India plans two-fold renewable energy increase

The Indian Government's latest Five-Year Plans are targeting a two-fold increase in renewable energy production by 2012. If the target is achieved, renewable energy sources will account for 5% of India's total forecast 200,000 MW of installed electricity generation capacity by that date, writes *David Hayes*.

Street scene in Mumbai, India

Since the mid-1980s India has established one of largest and fastest growing renewable energy programmes in Asia, aimed at developing small scale, community-based and captive industrial energy production in order to reduce power shortages throughout the country and provide many remote rural villages with electricity for the first time. In spite of being a government initiative, most renewable energy is being developed by private companies. However, plans now call for a two-fold increase in renewable energy production during India's tenth and eleventh Five-Year Plans that run from 2003–2007 and 2008–2012 respectively. If the target is achieved, renewable energy sources will account for 5% of India's total forecast 200,000 MW of installed electricity generation capacity in 2012.

According to the Ministry of Non-Conventional Energy Sources, India has a renewable energy generation potential of about 100,000 MW – of which about 3,500 MW, equivalent to 3.5%, has been harnessed so far. The government's long-term target is for the national power generation capacity from renewable energy to reach 10,000 MW by 2012, equivalent to 10% of the country's ultimate renewables potential capacity.

By 2012 the government aims to use renewable energy to achieve the electrification of 18,000 remote villages currently lacking mains power supplies. About 4,000 of the villages are planned for electrification using solar photovoltaic systems and other renewables-fuelled power plants – a target one and a half times the 2,700 Indian villages and hamlets that already have been electrified using this technology. Other villages will be electrified using biomass, small hydroelectric and hybrid power systems.

Biogas is another large potential source of energy for residential consumers. To date, about 3.5mn family-type biogas systems have been installed across India, less than one-third of the total 12mn biogas systems that the government estimates could be built.

Wind power is one of India's largest renewable energy resources. A wind farm capacity totalling a potential 45,000 MW is capable of being developed, of which a little over 1,700 MW has been built so far. Meanwhile, biomass cogeneration schemes are the second largest potential source of renewable power generation, boasting a potential capacity of 19,500 MW – of which just 468 MW has been developed to date.

According to the Ministry, small hydropower projects up to 25 MW offer a potential power generation capacity of about 15,000 MW. So far, 453 small, mini and micro hydroelectric projects totalling 1,463 MW have been built, while a further 4,215 small, mini and micro hydro sites have been identified, offering a further combined potential capacity of 10,279 MW.

Other potential renewable energy sources include waste-to-energy projects that could generate around 2,500 MW; also solar water heating, geothermal, ocean current and other energy schemes.

Promoting renewables

For almost two decades the leading government organisation promoting the commercialisation of renewable energy has been the Indian Renewable Energy Development Agency (IREDA). IREDA was set up in 1987 to finance and develop India's renewable energy sector. The agency's aim has been to motivate the private sector to participate in commercial renewable energy ventures to produce electricity and heat energy. IREDA also supports energy conservation due to the various synergies between renewable energy and energy conservation.

Since its creation IREDA has been at the forefront of renewable energy financing in India, having funded 1,635 projects and creating a portfolio worth almost Rs20bn. Operating at a profit since its inception, the agency has gained the trust of the World Bank, Asian Development Bank and bilateral development agencies through its well-managed activities.

IREDA borrows from multilateral development banks and agencies, using the loans as revolving credit to on-lend to private companies to finance numerous small renewable energy projects. To date IREDA is estimated to have loan-financed about 30% of all privately undertaken renewable energy projects in India. 'We are fairly successful, with 80% to 90% of our projects in a limited and new field,' commented an IREDA source. 'This is a unique operation. Because of our success we are getting second lines of credit from multinational development banks and foreign institutions. Other institutions are funding these projects now like commercial banks. Other organisations getting commercial loans require government guarantees or infrastructure funds. Multilateral bank funds for renewables are given only to IREDA to disburse.'

IREDA supports power projects up to a maximum of 25 MW installed capacity. Among the various renewable energy sources available, small hydropower projects are most likely to approach this 25 MW size limit.

Traffic in Mumbai

The IREDA source also noted that wind energy farms are generally a maximum of 10 MW to 15 MW in size. However, the introduction of 1.2 MW wind turbines into India has resulted in wind farms of 5 MW to 10 MW now becoming more common. Medium-sized industrial enterprises borrowing from IREDA to build a wind energy plant usually install wind turbines totalling 1 MW on average. For developers of micro hydropower schemes the minimum project size supported by IREDA is 100 kW.

Taking a lead in wind power

India has, in fact, already taken a lead in wind power development in Asia. Since launching its wind power programme in 1984 the country has made considerable progress in harnessing one of India's largest natural sustainable electricity generation sources. Aimed at providing households and industry with low-cost electricity supplies, India's wind energy programme continues to expand, supported by rising investment in wind power farms and a steady increase in the number of factories producing wind turbine generator equipment.

India's wind power programme is supported by what the government claims is the world's largest wind resource assessment scheme. This has been carried out by the Centre for Wind Energy Technology in southern Tamil Nadu state, along with agencies in each of the country's states and other agencies, including the Indian Institute of Tropical Meteorology. Research continues to identify regions and sites offering additional wind power potential.

The government has plans to develop a further 6,000 MW of wind power by 2010, an ambitious target compared with other countries in Asia. Most wind power potential is located in 14 states in western and southern India – in particular Tamil Nadu, which has about half India's wind farm capacity, as well as Gujurat, Maharastra and Andhra Pradesh.

According to Ministry statistics, about 95% of India's existing wind power capacity is operated by privately funded companies. The remaining capacity is operated by state power utilities and other official organisations. Around 80% of present wind energy is consumed as captive electricity by wind power producers, while the remainder is sold as surplus power to the state grid. Some wind power farms owned by industrial enterprises generate for their own use only.

The growth in the construction of wind farms has resulted in a rise in the number of companies producing wind power equipment in India. A number of foreign companies have set up local factories, mostly in partnership with Indian firms. Over 15 companies currently make wind turbine equipment, many of which are joint venture companies. In addition, several Indian companies produce wind turbine equipment under the licence of foreign manufacturers.

About 80% of parts used are locally made. Blade manufacturing facilities have been established in India that can operate wind power generators up to 750 kW installed capacity. Wind turbine equipment with an installed generating capacity exceeding 500 MW can now be produced each year in India.

Photos: David Hayes

Potential for growth

Central and Eastern Europe is one of the few remaining growth markets for oil and gas in the western hemisphere. As accession of many of its countries into the European Union has just taken place, *Wolfgang Ruttenstorfer*, CEO of OMV, Central and Eastern Europe's largest integrated oil and gas company, analyses the potential for growth in the region and explains the challenges of exploring and producing oil and gas in what is largely a region of mature fields.

The Central and Eastern European market is a unique region in which to run an integrated energy company. It is one of the few markets in the western hemisphere where car ownership and demand for oil and gas products is rising rapidly.

The region is bisected by the Danube River, which is some 2,800 km long and is still used as an industrial supply chain, as it has been for centuries. Today, the Danube forms a natural, cost-effective artery on which to transport oil, amongst other heavy goods. The core of the energy-purchasing Central and Eastern European market stretches some 500–700 km east and west of the river, encompassing territory from southeast Germany to the Czech Republic, Slovakia, Hungary, Slovenia, Croatia, Bosnia, Serbia, Bulgaria and Romania. To put the scale of the area into headcount terms, it consists of around 100mn people.

EU accession

Accession to the European Union (EU) has been, and continues to be, a fundamental economic driver in the region. Significant levels of financial transfers from Brussels to the accession countries have taken place to prevent, as far as possible, the enlarged Eurozone from becoming a multi-speed economy. As a result, the GDP of these regions is growing at a higher rate than would otherwise be the case, with demand for energy-related products rising in concert with this wider economic uplift.

Furthermore, while the EU accession story is now being priced in to stock markets, the underlying growth fundamentals remain strong. For instance, Romanian consumption of petroleum currently stands at around 10mn t/y. With 128 motor vehicles per thousand inhabitants, the motorisation rate is far below the Central and Eastern European average. However, the spending power could increase if Romania was to join the EU in the next accession round.

It is also worth noting that, despite the general upward trend, these markets are starting from a very low level of income per person. What this means in practice is that the markets here remain quite sensitive to energy prices. Fluctuations in the price of oil, gas and other energy-related commodities can have immediate repercussions on the regional economy, particularly in the less advanced areas.

Operating in Central and Eastern Europe presents its own unique challenges and opportunities. These are emerging markets, each with its own currency, regulatory and legal framework, and cultural identity. Furthermore, this is not virgin territory for energy companies. The supermajors, of which the region is largely now devoid with one or two notable exceptions, have been criticised in the past for their *modus operandi* in the region. Success depends on partnership with local expertise, bringing an international perspective in union with local knowledge and entrepreneurialism.

E&P challenges

The challenges that the Central and Eastern European market poses in terms of exploring, developing and rejuvenating energy fields, and then refining and marketing the product, are different to those in younger markets. E&P in this environment demands experience of using new technologies in the appropriate way to extract every last drop from a mature field.

One of the great advantages of applying new technology – such as 3D and 4D seismic modelling – is that it enables energy companies to go back to the mature fields and use enhanced oil recovery methods to extract further oil and gas from near or exhausted fields. For instance, the Austrian Matzen oil field, Central Europe's largest, is now being rejuvenated through the use of leading-edge E&P technologies, ensuring that Austria can continue to produce oil for years to come.

As a result, the technologies that are going to have a major impact on the upstream industry in Central and Eastern Europe are those that recognise that information and knowledge are key requirements. Technology must work towards the desired end of extracting oil in a safe, environmentally friendly and economic manner. This is best achieved by collecting as much data as possible before the drilling process begins. Extracting maximum value from existing energy fields will be vital to minimise the cost of providing oil and gas to the burgeoning energy demands of Central and Eastern Europe. ●

OMV – some facts and figures

With Group sales of 7.64bn, over 6,000 employees in 2003 and a market capitalisation of 4bn, OMV is Austria's largest listed industrial company and the leading integrated oil and gas group in Central and Eastern Europe. In 2003, for the third year in succession, the Group consistently outperformed the FTSE Oil and Gas Index.

OMV is active in the refining and marketing (R&M) sectors in 12 Central and Eastern European countries and has exploration and production (E&P) operations in 16 countries. The company is half-way to achieving ambitious growth targets set for 2008 (unveiled when Ruttenstorfer took over as CEO in 2001) – a doubling of downstream market share to 20% and a doubling of oil and gas production to 160,000 boe/d.

In gas, OMV acts as a core hub in Central Europe via its Baumgarten facility, which transports one-third of Western Europe's consumption of Russian gas. The Group is the world's largest international gas operator in Pakistan and it is a partner in the Nabucco consortium that is currently researching the potential for a natural gas pipeline that will connect the Caspian/Middle East with Europe.

OMV also has storage facilities, a 2,000-km pipeline system and sells some 41bn cm/y of gas. The Group also operates integrated chemical and petrochemical plants and holds a 25% stake in Borealis, one of the world's leading polyolefins producers. ●

Photos: www.lukoil.com

Kazakh oil helps meet Chinese demand

China moved a step closer to ensuring the security of its energy supplies when it signed an agreement with Kazakhstan to build a 998-km pipeline from central Kazakhstan to Western China. *Chris Pala* provides a project update.

The Kazakhstan–China pipeline is the second and largest of three pipelines that will plug gaps in Kazakhstan's network to facilitate the transport of oil from the vast deposits of the Caspian Sea to the Chinese border. The deal – which Beijing has been pushing since it signed a general agreement of purpose with Astana in 1997 – comes at a time when Moscow appears to have decided to send some of its Siberian oil towards Japan rather China, despite China's entreaties.

At the time of signing the agreement on 18 May during a state visit to Beijing by Kazakhstan President Nursultan Nazarbayev, Kazakh Foreign Minister Kassymzhomart Tokaev stated: 'All financial and technical issues relating to the construction of the Atasu–Alashenko pipeline have been resolved.' China is to pay 49% of the $700mn cost and Kazakhstan 51%. Tokaev also said that the agreement 'provides for a start in the nearest future and a conclusion [of construction] by the end of 2005'. Initial capacity will be 10mn t/y, to be doubled in five or six years.

According to Caspian analyst Laurent Ruseckas, the deal was mostly driven by China, which, he said, 'needs to secure supplies more than Kazakhstan needs another export route'.

Kazakh exports

While China's energy consumption is soaring, Kazakhstan already exports its crude by the US-built CPC pipeline to Novorossiisk, Russia, on the Black Sea; by rail and pipeline to Russia and China; and by ship and rail to Iran. It is expected to send a substantial part of future oil from the super-giant offshore field at Kashagan into the Baku–Ceyhan pipeline, which is currently under construction.

For Kazakhstan, sending its oil east to a single buyer should not be a problem. 'With the option to sell their oil to other clients, the Kazakhs will be able to keep their prices up,' Ruseckas said. 'China will be paying a premium for the Kazakhstani oil because it will be more expensive to transport east. I presume they will agree on a price formula that will take this into account.'

But there's more in it for Kazakhstan than simply a route for exporting its own oil. 'The Chinese are very interested in having Russian oil come south from Siberia and be exported to China through the new pipeline,' Tokaev commented in a recent lengthy interview. 'This is a win-win situation for everyone,' he stated.

Today, most Kazakh oil transits through Russia, giving Moscow a lever. Having Russian oil transit through Kazakhstan would level the playing field.

Caspian development

In addition to the pipeline deal, Kazakh and Chinese officials in Beijing also signed a framework agreement on Chinese participation in the exploration of the Kazakh sector of the Caspian Sea, where more than 100 offshore blocks are due to be eventually developed with foreign capital and expertise.

CNPC (China National Petroleum Corporation) already operates several fields that produce more than 10% of Kazakhstan's output of 1mn b/d, which is due to triple within 15 years. Production is exported in both directions – some to China and some to Russia and the west. The largest field, CNPC-Aktobemunaigas, is expected to produce 5.4mn tonnes of oil this year. Meanwhile, the North Buzachi field – which is half-owned by Nelson Resources, a company that is widely believed to have ties to President Nazarbayev's family – is expected to produce 433,000mn tonnes this year.

The Kazakstan–China pipeline agreement makes independent PetroKazakhstan, the easternmost major producer in the country, of particular interest to CNPC. Formerly known as Hurricane Hydrocarbons and the largest intergrated oil company in Kazakhstan, PetroKazakhstan produces 7.1mn t/y of oil, of which 1mn t/y already goes to China via pipeline to Atasu and then by rail. Petrokazakhstan's main field, Kumkol, is located in the centre of the country, on a main east–west pipeline.

Last year, work completed on a pipeline linking Atyrau, Kazakhstan's main oil centre just north of the Caspian, to Kenkiyak, the site of CNPC-Aktobemunaigas' main field.

Once the pipeline segment agreed to in Beijing is completed next year, the initial capacity of 10mn t/y could be filled with oil from CNPC-Aktobemunaigas, North Buzachi and Petrokazakhstan, analysts say. However, a spokesman for Petrokazakhstan declined to comment on the possibility of the company increasing its sales to China.

Plugging the gap

When the Atasu–Alashenko segment is completed, the last remaining gap in a pipeline network that will span Kazakhstan's 3,000-km breadth will be from Kenkiyak to Kumkol, running east from Petrokazakhstan's main field. When that last 600-km gap is completed – no date has been set – then all of the Caspian region's production will become available for transit to China.

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Wednesday 22 September 2004

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Guest of Honour and Speaker
Jeroen van der Veer (right)

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

The management of change has been a constant feature of his postings, especially at Shell Nederland, where he was Managing Director and oversaw the investment of $2 billion in the 'Per plus' project at Pernis – one of the largest of Shell's operations worldwide, including both refining and chemicals manufacture.

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

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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 ☐

Photocopies of this form *are* acceptable

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