# Petroleum review

AUGUST 2004

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*Jointly organised by the Energy Institute and The Worshipful Company of Fuellers*

**Wednesday 22 September 2004**

London, UK

In the period to 2010 the sources of Britain's energy supplies are set to change rapidly as North Sea oil and gas production declines. By 2010 the UK will already be a large-scale importer of gas and coal while oil imports will be increasing steadily.

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- **Stephen Timms MP**, Minister of State for Energy, E-Commerce and Postal Services

**Speakers include:**

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- Ken McKellar, Managing Director, Corporate Strategy, Deloitte Petroleum Services
- Paul Cuttill, Chief Operating Officer, Networks, EDF Energy
- Professor John Gittus, Consultant, Chaucer Holdings
- Simon Stringer, Director Homeland Security, BAE Systems
- William Adamson, Vice President and General Manager, UK Downstream BG Group plc
- Mike Smith, Head of Energy Analysis, BP Group Economics Team
- Tony Cooper, Chairman, NIA

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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 pictures: Vopak's Europoort terminal in Rotterdam. See p12.**
*Photo courtesy of Vopak*

**Iceberg: The Newfoundland offshore petroleum industry produces around one-third of Canada's conventional light crude. See p30.**
*Photo courtesy of Provincial Airways*

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## news



## special features



## features



## regulars



# Global oil production now flat out

By the time this is being read, currently available oil production capacity all around the world will be producing flat out. How sustainable this proves to be remains to be seen.

For many years now non-Opec production has been operated at capacity, leaving Opec to fine tune production in order to achieve its price objectives. In economic terms, because no company or country had the capacity to challenge Opec, they had no choice but to be price takers, maximising earnings by maximising production.

Opec's record production of 31.7mn b/d in 1977 wasn't exceeded until November 2003, since then it has never been under that level. It reached 32.2mn b/d in March, dropped back a little in April and May, and then in June reached 32.65mn b/d.

The utilisation of the final bits of readily available capacity in Saudi Arabia – in line with the 0.5mn b/d expansion in Opec quotas from August – means that early August production will exceed 33mn b/d. After that, the only incremental capacity is the, definitionally unsustainable, surge capacity plus any new capacity that comes onstream. On p38 *Petroleum Review* has tabulated the most up-to-date version of its megaprojects database. Although one or two projects have been added since it was last published (*Petroleum Review*, January 2004 – unfortunately now out of stock). Most of the changes are project delays, most notably the Nigerian offshore Bonga, Erha and Agbami projects.

On p42 is *Petroleum Review's* annual re-presentation of global oil production from the latest *BP Statistical Review*, June 2004. This shows that 18 major oil producers are now in decline, handsomely offset by rapidly expanding production from the 15 countries growing at over 5%/y and the eight growing at over 10%/y. A straw in the wind, however, is that decline is now running at over 1.1mn b/d and there is evidence of decline rates increasing.

The feature on p18 confirms the view that the industry is now making a massive commitment to new LNG projects. This potential investment boom is being driven by three factors – the desire to monetise stranded gas, the need to make up for US and Canadian gas production shortfalls, and the attractions of probably the fastest growing area of the whole oil and gas business – LNG. As part of this feature we have produced our first tabulation of all the gas megaprojects. What this clearly shows is that if all these LNG and GTL projects go ahead, by the end of the decade there will be few gas discoveries not in production or queued for production. Equally certain is that declining gas production in Canada and the US is providing a major, and potentially rapidly growing, market for LNG. Our annual reviews of recent developments in the US and Canada are on p14, 24 and 30.

On p26 Dr Salameh tackles the thorny question of how accurate are Middle East reserve estimates. His conclusion that these may be overstated by up to 300bn barrels, or roughly five North Seas, will certainly give pause for thought. If his assessments are right, the world faces very major challenges in developing and securing the oil supplies it will require.

However, the most imminent concern must be the latest developments in Russia. The nerve twisting drama of Yukos and the tax demands has now taken a dramatic and deeply disturbing twist. It now appears that the tax authorities wish to remove the bulk of Yukos' production assets and so, we are told, sell them for a fraction of their worth. If this proves true, the hopes that Russia could be safely invested in, with law and regulation being fairly applied, are undermined. Investors with liquid assets will leave, those left will not be sure if they have paid good money for assets or liabilities. If the situation is not regularised very quickly – by Presidential intervention if necessary – then the outlook is very bleak indeed.

*In the preparation of our megaprojects tables every effort has been made to ensure they are as accurate as possible. Our time and resources are necessarily limited, so if any reader has better information we would be very pleased to hear from them. We extend our thanks to all who have helped in the past.*

The Energy Institute is to hold a major conference on oil depletion on 10 November, in which all aspects of the topic will be discussed. For further details, contact the EI Events Department t: +44 (0)20 7467 7100 or **www.energyinst.org.uk**

*Chris Skrebowski*

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

## e-world

A new guide for operators of UK service stations has recently been launched in a move designed to make filling up with petrol less of a daunting task for disabled motorists. The guide is available on UKPIA's website at **www.ukpia.com** under 'Publications'.

**www.coppernickel.org** is a new website that provides detailed information and solutions for designers, engineers, fabricators and users of copper-nickel alloys.

The UK DTI and LOGIC have launched an Oil and Gas Trust Scheme (**www.og.dti.gov.uk/portal_files/dig_trust.htm**) for issuing digital certificates as part of the regulatory processes governing North Sea oil and gas operations. The first use of digital certificates will be signing digital environmental consents and notices from the UK Oil Portal (**www.og.dti.gov.uk**), which has been designed to comply with government e-commerce targets, such as conducting business electronic and paperless, whilst at the same time delivering real benefits in terms of more efficient ways of conducting business.

The second edition of the *Little Black Book of Oil Spill Contractors* contains contact information for over 1,000 oil spill response organisations in 50 countries around the world. An online version is available from **www.cleanupoil.com**

Classification society ABS has published technical guidance on the use of inert gas systems for ballast tanks on double-hull tankers. The new guide addresses industry concerns about the potential for volatile gases to leak from oil tanks to ballast tanks and void spaces, leading to the possibility of explosive atmospheres that could endanger vessels. A copy of the guide can be downloaded from **www.eagle.org/rules/downloads/131-IGS.pdf**

Intertanko and the International Chamber of Shipping (ICS) have prepared a joint position paper emphasising that the recently ratified MARPOL Annex VI will enter into force in May 2005, as well as providing the reasons for the international shipping community's difficulty in accepting the EU's draft directive on sulphur content in marine fuel. The one-page position can be accessed from **www.intertanko.com/pdf/weeklynews/INTERTANKO-ICSpaper.pdf**

PX Group has integrated UKPX into the APX Group, strengthening APX's UK power offering. For further information, visit **www.ukpx.co.uk**

# In Brief

## UK

***Total E&P UK and partners BG Group,*** *Eni, GDF Britain and Ruhrgas have announced the go-ahead for the development of the high pressure/high temperature (HP/HT) sour gas condensate Glenelg field located in the central North Sea. The field will be developed as a satellite to the existing Elgin/ Franklin facilities and associated infrastructure. Production start-up is scheduled for 3Q2005.*

***BP expects its average oil and gas pro****duction to rise to 4mn boe/d this year, up 10% from 2003. This includes volumes from the company's 50% share in Russian oil major TNK-BP. Production from BP's portfolio outside Russia is expected to show a fall from 3.184mn boe/d in the first quarter..*

***A new oil exploration company has*** *been created in the Falkland Islands. Falkland Oil & Gas (FOGL) has been set up together with Global Petroleum and funds managed by RAB Capital. FOGL and Hardman Resources are to invest $4.5mn in funding a work programme offshore the Falkland Islands, in leads reported to exhibit the potential to contain 200mn to 2.5bn barrels of oil.*

***Aker Kvaerner has entered into a pre****bid agreement (PBA) for onshore disposal of the Total-operated Frigg field platforms and associated equipment with the Shetland Decommissioning Company (SDC), SBS Logistics and Onyx UK involving the development and exclusive use of the Greenhead base in Lerwick, Shetlands.*

## Europe

***Norsk Hydro recently awarded Aker*** *Kvaerner the first large Ormen Lange gas terminal contract, valued at some NKr2bn. The EPC contract covers engineering, procurement and construction activities for the gas reception and export area in Nyhamna on the northwest coast of Norway. Construction activities will start at the Stord and Verdal yards in May/June 2005.*

***The plan for development and opera****tion (PDO) of Statoil's two Norne satellites, Svale and Stær, in the Norwegian Sea has been approved by the Ministry of Petroleum and Energy. The project involves developing the two fields with three subsea templates tied back*

# NEWS Upstream

## Amec yard ships out BP's Clair deck

**BP's Clair deck left Amec's Wallsend, Tyne and Wear, yard on 29 June to begin a two-day journey to her new home 75 km west of Shetland. Fabrication and integration of the deck, which weighs over 11,000 tonnes, was successfully completed in 18 months by Amec, who will now carry out hook-up under a £10mn contract. The company will assemble the deck on to its jacket and hook up the drilling support module, living quarters, flare stack, waste heat recovery unit and stair towers. First oil from the Clair field is targeted for late 2004.**

**Lifting and transport firm Mammoet, who undertook the load-out of Clair at the Wallsend yard, have nominated her for an official world record as 'the heaviest object ever to have been moved on wheels on land'.**

## *Barrancas gas project gets underway*

Venezuela's President Hugo Chavez has inaugurated the first well in Repsol YPF's Barrancas project in the southwest of the country. There are five potential fields in the Barrancas block – Sipororo, Guaramacal, Guaramacal Sur, Barrancas and La Yuca. In this first exploration phase, a discovery well called Sipororo 2X will be drilled and the Sipororo 1X well drilled in the 1990s by PdVSA will be recovered. If these test positive, 3D seismic will be acquired to define drilling of the wells necessary for the project's full development. Discovery drilling at the Guaramacal site will be undertaken in a second exploration phase.

First gas is expected in 1H2005, reaching 2mn cm/d in 2006. Production has been earmarked as feedstock for a 45-MW thermoelectric power station to be installed in the Obispos municipality, in the state of Barinas.

In addition, Venezuelan officials have authorised an increase in current gas production at the Quiriquire block of 3.4mn cm/d, including associated liquids, making Repsol YPF the principal private gas producer in the country.

## Suncor reduces production target

Citing unscheduled maintenance at the company's oilsands operation in northern Alberta in June, Suncor Energy has reduced its production target for the year to an average 220,000 b/d, down from an original target of 225,000–230,000 barrels. The figure excludes the Firebag project's in-situ bitumen production, which is expected to average about 20,000 b/d over 2H2004.

Suncor is also understood to have stated that higher natural gas fuel costs, along with the reduced production and costs associated with unplanned maintenance, have resulted in higher oilsands operating costs. The company said it expects cash operating costs, excluding Firebag, to average $12/b to $12.50/b for the second half and full year. The company had originally targeted 2004 cash operating costs at $10.75/b to $11.75/b.

## DeepStar to develop new semisub

DeepStar, a group comprising 10 leading deepwater operators,* has awarded Aker Kvaerner a contract for a study to develop a semisubmersible production platform for use in ultra-deepwater field developments down to 10,000 ft. In addition to the development of the floating platform itself, the scope includes other critical aspects such as design of the risers that will bring the oil and gas from the well to the surface. It also includes installation methods for mooring systems and risers.

The Aker Kvaerner Deep Draft Semisubmersible (DDS) – which the group has spent the last three years developing – will form the basis for the study, which is due to complete by the end of the year.

**The DeepStar Phase VII participants are Anadarko, BP, ChevronTexaco, ConocoPhillips, Eni, Kerr-McGee, Marathon, Petrobras, Total and Unocal.*

## Drilling on the NCS

Production drilling contracts worth a total of NKr3.3bn over four years have been awarded by Statoil to Norway's Odfjell Drilling Management and Smedvig Offshore. The assignments relate to the Tampen area of the North Sea and the Heidrun field in the Norwegian Sea, and involve work on 10 Statoil-operated platforms. The jobs have been collected into three contract packages with a firm period of four years and three renewal options, each of two years.

Smedvig has secured the production drilling assignment on Statfjørd and Gullfaks in the Tampen area, which is worth NKr1.7bn for the firm four-year period. The other packages have gone to Odfjell for Tampen fields Snorre and Visund and for Heidrun. They are worth NKr1.2bn and NKr450mn respectively for the initial four years.

The contracts embrace about 30% of all production drilling on the Norwegian Continental Shelf (NCS).

## *Licence swaps*

**Total has concluded an agreement on swapping licence holdings on the Norwegian Continental Shelf under which Total's interests in the Statoil-operated Mikkel and Åsgard fields in the Norwegian Sea will be harmonised and the company also increases its share of Kristin. At the same time, Statoil is acquiring a 10% holding from Total in Hydro's Tune development in the North Sea. In addition, Statoil will receive a cash payment.**

**The agreement gives Total 7.65% of Mikkel, identical to its current holding in Åsgard. Total increases its share of Kristin by 3% and equalises its holding in production licences 134, 199 and 257 that include the Norwegian Sea field. A partial balancing of licence interests in the Øseberg area of the North Sea will also be achieved by the deal.**

**After the transaction with Total, Statoil will have a 33.97% stake in Mikkel, 41.6% in Kristin, and 10% in Tune.**

## Japan and China set to dispute?

Japan's Industry Minister Shoichi Nakagawa was understood to have stated that the country would start exploring for natural gas resources in its exclusive economic zone (EEZ) in the East China Sea in July, in a move that some industry pundits said appeared to be a plan to counter China's oil exploration near the area. Earlier in June, the Japanese Government was reported to have lodged a complaint with Beijing that a Chinese gas project could violate the boundaries of Japan's EEZ, after learning the Chinese had begun constructing a drilling facility nearby. Japan argues that it has a right to claim its share if resources are found straddling the intermediate line. Up to 200bn cm of natural gas reserves are estimated to exist in several fields in the area.

China is reported to have expressed 'grave concerns' about Japan's announcement and Chinese officials announced that China would send ships in July to conduct research on the Japanese side of the area divided by the intermediate line.

The United Nations (UN) Convention on the Law of the Sea allows coastal countries to regulate seabed resources in their economic zones, which extend 370 km from their shores. However, Beijing and Tokyo, both of which signed the convention in 1996, are unable to agree over the zones as they partly overlap. China maintains that the border is where the continental shelf ends, as is the international custom. But Japan contends that both zones meet halfway between the shores. The UN says it will decide on global offshore territorial claims by May 2009.

China has suggested that the two countries should develop the area together, but Japan is reported to have refused, saying it first wants Beijing to provide information from studies it has already completed.

## In Brief

*to the production ship on Norne. It is scheduled to begin producing in the autumn of 2005, with a forecast output of just under 70,000 b/d of oil.*

***Petroceltic International is reportedly** buying up to a 40% stake in two permits covering blocks BRG 490 (offshore) and Civitaquana (onshore) in Eastern Italy. BRG 490 is thought to contain 100–300mn barrels of recoverable oil. The company will acquire an initial 15% interest from Rigo Oil, with an option to boost its stake to 40%.*

***Norsk Hydro has concluded its dia**logue with the US Securities and Exchange Commission's Division of Corporation Finance (SEC) regarding Hydro's estimate of the 'proved undeveloped reserves' for the Ormen Lange gas field. Based on the outcome of the dialogue with the SEC, Hydro has decided to book in the 2003 Form 20-F its 18.07% share in Ormen Lange at 234mn boe, which is 102mn boe lower than the reserve figure estimate in the 2003 annual report to shareholders.*

### North America

***EnCana is set to sell conventional oil** and gas assets in Alberta producing approximately 16,800 boe/d to Harvest Energy Trust for approximately $395mn (C$526mn) before adjustments.*

***Fortuna Energy, a wholly owned sub**sidiary of Talisman Energy, has acquired all of Belden & Blake Corporation's Trenton/Black River assets in the Appalachia region of the US for $65mn.*

### Middle East

***DNO of Norway is understood to have** entered into an agreement with the Kurdistan regional government to explore for, and develop, oil and gas in northern Iraq.*

### Russia & Central Asia

***KazMunaiGaz is reported to have** produced 4.245mn tonnes of oil and gas condensate in 1H2004, up 9.4% year-on-year and 194,000 tonnes over target for the period. Natural gas production in 1H2004 amounted to 438mn cm, which was 0.6% over target for the period.*

# In Brief

***China National Petroleum Corporation** (CNPC) is reported to have secured a high-yield well at the subsalt oil pool in western Kazakhstan's Kenkiyak oil field. The well, H-8010, is producing at above 1,100 t/d of oil. The Kenkiyak field currently produces 2,750 t/d. Proven oil reserves are put at 110mn tonnes. A further seven new wells are expected to start producing from the subsalt reservoir by the end of this year, doubling overall production from Kenkiyak to 2mn t/y.*

***Sibneft's proved oil and gas reserves** grew to 4.779bn boe on 1 January 2004, up from 4.718bn boe the previous year, according to a reserve audit recently completed by US firm Miller & Lents to specifications set by the Society of Petroleum Engineers.*

***Kazakh Energy and Mineral Resource** Minister Vladimir Shkolnik is reported to have declared that Kazakhstan has a priority right to buy British Gas' interest in the international consortium Agip KCO, operator of the Kashagan project. Agip KCO partners are Eni, ExxonMobil, Shell and TotalFinaElf, each with a 16.67% interest, and ConocoPhillips and Inpex, each with 8.33%. BG has announced its withdrawal from the project and the other participants wish to buy its 16.67% share.*

***Russian oil production is reported to** have reached 9.21mn b/d in June 2004, implying an increase of 1.9% month-on-month and 9.8% year-on-year.*

***Gas production in Turkmenistan is** reported to have increased 3.9% year-on-year to 32bn cm in 1H2004, while oil production remained unchanged at 4.7mnn tonnes.*

***Lukoil has signed a 35-year production** sharing agreement (PSA) on the Kandym-Khausak-Shady project in Uzbekistan. First gas is expected in 2007. Recoverable reserves are put at 283bn cm.*

### Asia-Pacific

***Shell has given the green light for the** development of the Pohokura gas field, having signed off the final investment decision. First gas is slated for mid-2006.*

***The Indonesian Government is** reported to have launched the tender process for 10 oil and gas areas*

# NEWS Upstream

## UK oil production down again

**UK oil production in April 2004 fell by 7.1% against April of last year – the 17th consecutive month where UK oil production fell on a year-on-year basis – according to the latest (June) Royal Bank of Scotland *Oil & Gas Index*. Production also fell on the month by 3.1%, averaging 1.94mn b/d – the lowest since last August 2003. UK gas production averaged 12,078mn cf/d in April 2004, up 11.1% on the year.**

**'April saw the pace of decline in UK oil production slow, but at 7.1% on the year it still remains high. However, revenues are being maintained by the combination of strong growth in gas production and high oil prices,' commented Tony Wood, Senior Economist with the Royal Bank.**

**There was little change on combined oil and gas production at just over 4mn boe/d, which was marginally down by 1.5% on the month and slightly up by 1.6% on the year. High oil prices in April helped ensure that North Sea revenues were maintained, despite declining oil production.**

| Year Month | Oil production (av. b/d) | Gas production (av. mn cf/d) | Av. oil price ($/b) |
|---|---|---|---|
| Apr 2003 | 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 | 11,342 | 30.89 |
| Mar | 2,006,160 | 12,090 | 33.72 |
| Apr | 1,944,252 | 12,078 | 33.36 |

*Source: The Royal Bank of Scotland* Oil and Gas Index

North Sea oil and gas production

## *UK offshore safety case proposals*

The UK Health and Safety Commission (HSC) has published a consultation document on proposals to replace the Offshore Installations (Safety Case) Regulations 1992. The Commission proposes improvement to the regulations and control of major hazards offshore by strengthening the safety case regime. Specifically the document details proposals for:

- Replacing three-yearly safety case resubmissions with five-yearly thorough reviews.
- New duties for licensees to take safety into account when appointing an operator.
- Replacing some safety cases with notifications, removing some existing safety case particulars and making some others better focused.
- Replacing the requirement to demonstrate major accident risks are 'as low as is reasonably practicable' with a demonstration that such risks are identified and relevant statutory provisions are complied with.
- Introducing a new fallback power directing the duty holder to revise a safety case.
- Introducing a statutory right of appeal against regulatory decisions to the Secretary of State.
- General updating throughout and consequential amendments to related regulations.

The opportunity would also be taken to propose a small amendment to the Offshore Installations (Prevention of Fire & Explosion, and Emergency Response) Regulations 1995 (PFEER) to clarify that rescue and recovery arrangements should always include external parties, such as coastguard and helicopter support.

Copies of the proposals to replace the Offshore Installations (Safety Case) Regulations 1992 can be accessed via HSE's website at **www.hse.gov.uk/consult/live.htm**

# Connecting Perm region gas fields

**Lukoil has approved the development of a system to gather, treat, transport and utilise associated gas produced in the northern part of the Perm region by Lukoil-Perm. The new system will connect three large fields in the Karsnovishersky and Solikamsky districts – Ozernoye, Magovskoye and Logovskoye – all of which produce oil with a high gas-oil ratio. At present, all produced gas is being flared.**

**The 180-km inter-field gas grid, construction of which will begin in 2005, will be connected to the trunk pipeline at the Unva terminal in the Usolsky district of the Perm region. From there the gas will be taken to the Lukoil-owned gas refiner Permneftegazpererabotka. The system will be commissioned in 2007 and is expected to achieve target capacity of 130mn cm/y of gas in 2010. Beginning in 2015, the system will also start receiving 50mn cm/y of gas from the gas cap of the Magovskoye field.**

## *First gas from record-breaking Coulomb field*

Shell Exploration & Production Company (SEPCo) has produced first gas from the Coulomb development, which consists of the two deepest wells in the world in terms of water depth. The world record-breaking wells are located in Mississippi Canyon blocks 657 and 613 in the deepwater Gulf of Mexico and tied back via a 27-mile flowline to the BP-Shell Na Kika floating development system in Mississippi Canyon 474.

The Coulomb C-2 well is currently producing about 65mn cf/d of gas. Combined, C-2 and C-3 are capable of producing around 100mn cf/d. SEPCo has a 100% interest in the C-2 well, while Petrobras is a one-third partner in the C-3 well.

SEPCo reports that it completed the Coulomb C-2 and C-3 wells in successive, world-record water depths. 'These wells represent key industry and Shell firsts,' said Gaurdie Banister, Technical Director, Americas Region. 'On 2 May, the C-2 well became the world's deepest water depth completion in 7,565 ft (2.306 metres) of water. But records are made to be broken, and within 17 days, the C-3 well eclipsed the C-2 record depth by 5 ft, as it was set in 7,570 ft (2.307 metres) of water.'

# Some 180bn boe of reserves yet to find

According to a newly released study by Wood Mackenzie and Fugro Robertson there are 180bn boe of oil and gas reserves in deepwater, yet to find – more than twice the volumes already discovered. 'To date, the geography of deepwater has been the story of the 'Big Four' countries, Angola, Brazil, Nigeria and the US Gulf of Mexico,' explains Andrew Latham, Vice President, Energy Consulting at Wood Mackenzie. 'We have identified the potential for Mexico to join this elite group, once exploration work begins... Both the US and Mexico have risked exploration potential for many tens of tn cf of gas reserves which could be a major new source of gas into the North American market. In addition, Australia and Egypt have very substantial gas potential – each with yet-to-find potential of 80–120tn cf. However, market access for this resource will be limited in the near term.'

The rise of deepwater has coincided with a decline in exploration success elsewhere, with deepwater now accounting for around two-thirds of overall reserves in new oil and gas finds. The study concludes that most of the key deepwater plays should continue to achieve attractive returns ranging from around 12% to around 20% on a full-cycle basis. These constitute some of the best returns available from exploration, states the report.

# In Brief

*in Sumatra, Java, Madura, East Nusatenggara, Maluku and Papua.*

### *Latin America*

***Repsol YPF has begun drilling for oil*** *in Cuban waters in a narrow sector of the Gulf of Mexico, using a Norwegian drilling rig costing $200,000/day, reports* Monica Dobie. *The Spanish company is working with government-owned Cubapetróleo.*

***El Paso Production is to purchase a*** *Unocal affiliate that indirectly holds a 50% interest in UnoPaso – a joint venture that owns oil and natural gas assets in Brazil – for $61mn, with up to $19mn in additional payments that are contingent on attainment of certain natural gas price or volume thresholds. In addition, El Paso is acquiring Unocal's 30% interest in an adjacent exploration block.*

### *Africa*

***The Egyptian General Petroleum*** *Corporation's (EGPC) 2004 licensing round includes 15 blocks in the Gulf of Suez, Eastern Desert and Western Desert sedimentary basins of Egypt. The closing date for bids is 28 September. Further information can be found at* **www.egpc.com.eg**

***BP Egypt has signed an agreement*** *with Egyptian General Petroleum Corporation (EGPC) and Egyptian Natural Gas Holding Company (EGAS) to supply natural gas to the Damietta LNG Plant. In addition, BP Gas Marketing (BPGM) has signed an agreement to purchase LNG under a long-term contract from EGAS.*

***Apache reports that its Egyptian*** *Qasr-5 appraisal well has successfully extended the Qasr field to the southwest, further confirming the overall seismic structure of the Khalda Concession field.*

***Heritage Oil is reported to have said*** *that it could receive up to $58mn under terms of an option to sell royalty rights in the Congo M'Boundi field and Kouilou exploration permit to Maurel et Prom of France.*

***Apache has announced a new field*** *discovery in Egypt's greater Khalda concession. The Ozoris-4 well tested at a daily rate of 29.4mn cf of gas and 1,775 barrels of condensate.*

# In Brief

### UK

***Shell has published a quarterly break-** down of previously disclosed financial restatements for 2003 and 1Q2004 at* **www.shell.com/results**

***Centrica has sold the AA (Automobile** Association) to Permira and CVC for £1.75bn.*

***BP's 2003 Form 20-F, filed with the US** Securities and Exchange Commission (SEC) in Washington on 28 June, shows total proved reserves reported under SEC requirements are 23mn barrels more than those presented in its 2003 annual report and accounts to shareholders issued in March. For more details, visit* **www.bp.com**

***Shell has appointed Peter Voser as** Group Managing Director and Director of Finance of the Royal Dutch/Shell Group of Companies with effect from 4 October 2004.*

### Europe

***A private equity syndicate comprising** Candover, 3i and JPMorgan Partners has completed the acquisition of part of the oil and gas business of ABB, the Swiss-Swedish engineering group, for $925mn ( 729mn). ABB Lummus Global, also part of ABB's oil, gas and petrochemicals division, is not included in the acquisition. The new Group will be known as Vetco International.*

***The Norwegian Government has** reduced its stake in Statoil to 77.1%.*

***In Norway, Thorhild Widvey, formerly** State Secretary of the Ministry of Foreign Affairs, has been appointed Minister of Petroleum and Energy. Meanwhile, Oluf Ulseth, formerly Norway's State Secretary of the Ministry of Trade and Industry, has been appointed State Secretary of the Ministry of Petroleum and Energy.*

### North America

***James J Mulva is to succeed Archie W** Dunham as Chairman of the Board of ConocoPhillips.*

***Enron is reported to have received** court approval to emerge from bankruptcy. The company estimates that creditors will receive 19% of the $63bn they have been seeking.*

# NEWS Industry

## UK energy statistics for first quarter

The June edition of the UK Department of Trade and Industry's (DTI) *Energy Trends* reports that indigenous production of primary fuels was 65.4mn toe in 1Q2004, 10.4% lower than in 1Q2003, while final energy consumption in the period was 0.7% higher. On seasonally adjusted and temperature corrected annualised rates, total inland consumption on a primary fuel input basis was 247.9mn toe in 1Q2004, 0.9% higher than the same quarter in 2003. Between the first quarters of 2003 and 2004 coal and other solid fuel consumption fell by 0.9%. Oil consumption increased by 0.9%, while gas consumption rose by 2.7%. Primary electricity consumption decreased by 4.1%.

Provisional figures for 1Q2004 show that coal production (including an estimate for slurry) was 18.6% down on 1Q2003 at 6.4mn tonnes, with deep mined production down 22.4% and opencast production down 14.6%. Imports of coal in the period were 28% higher, at 8.9mn tonnes. Demand for coal in 1Q2004, at 18.1mn tonnes was 2.4% down on consumption in 1Q2003; consumption by electricity generators was down by 2.3%.

Total indigenous UK production of crude oil and NGLs in 1Q2004 decreased by 11% compared with 2003, to 25.5mn tonnes. Only five new fields came onstream after March 2003 and production from these fields was insufficient to make up for the general decline in production from older established fields. The UK retained its position as a net exporter of oil and oil products, with exports of petroleum products rising by 4% while imports fell by 20.1%. Overall primary demand for oil products in 1Q2004 was 0.8% higher than last year.

Meanwhile, total indigenous UK production of natural gas in 1Q2004 was 9.7% lower than in the corresponding quarter a year earlier. Compared with 1Q2003, exports of natural gas in 1Q2004 decreased by 61% and imports more than doubled. Demand for gas in the period was 1.8% higher than the level in 1Q2003.

*Energy Trends* and the DTI's *Quarterly Energy Prices* bulletins can be found at **www.dti.gov.uk/energy/inform/energy_stats_overview/index.shtml**

## Latest European Union developments

The European Union (EU) Council of Ministers has moved towards creating an effective cross-border gas market in the newly expanded EU, striking political agreement over a regulation on gas networks, reports *Keith Nuthall.* The new legislation harmonises the conditions for accessing gas transmission infrastructure, specifying third-party access, rules on capacity allocation, congestion management and the release of transmission information required for gas providers to use foreign systems. It should come into force in July 2006.

Meanwhile, the Council has agreed guidelines for EU investment in trans-European energy networks (TENs), considering their need to cover the 10 new member countries from eastern and southern Europe. The guidelines include objectives, principles and broad lines of action for boosting cross-border gas networks.

The need for action was underlined by a recent European Commission report on 'fixed networks' that said gas had performed worst, compared to telecoms, electricity and transport, in price and supplier choice terms, since the EU liberalised its utility markets.

In other EU news:

- Demand for low-sulphur fuels is expected to rise in Europe, with the Council of Ministers capping ships' $SO_2$ (sulphur dioxide) emissions in the EU by more than 500,000 tonnes annually from 2007.
- The European Free Trade Area (EFTA) Surveillance Authority has approved the abolition of a sulphur dioxide tax on oil refinery emissions in Norway.
- The EU's new constitution could provide national governments with the freedom to legislate on energy matters. It says that where the EU Council of Ministers has legislated on an energy topic, governments must ensure, in advance, that any new national rules do not 'contradict' EU laws.
- The Czech Republic has been given permission by the Commission to levy an excise duty reduction of  95 per 1,000 litres of blended diesel/biodiesel, where the biofuel is at least 31% of the final blend.
- Brussels has approved the acquisition of joint control of German light heating oil distributor Aral Wärme Service by Deutsche BP and BMV's OKTAN Mineralöl-Vertrieb.
- China and the EU have agreed to cooperate in the development of oil and gas industry technologies at an EU-China Energy Conference in Brussels.

# NEWS Industry

## Namibian gas-to-power project

**The Namibian power utility company NamPower, Energy Africa (90%, operator) and NAMCOR (the National Petroleum Corporation of Namibia, 10%) have concluded a joint development agreement regarding the planned Kudu gas-to-power project. The project involves the offshore development of the Kudu gas field by Energy Africa and NAMCOR, and the piping of gas to shore for treatment and delivery to an 800-MW power station to be developed and commercially operated by NamPower in the vicinity of Oranjemund, for conversion into electricity. All the produced electricity will be sold to NamPower for resale into the Namibian market and, in relation to the balance of electricity not sold in Namibia, to Eskom, the South African power utility company, for the South African market.**

**The primary objectives of the next phase of the project, which has already commenced, are to confirm the viability of the project, to complete detailed engineering and design work and to procure appropriate financing for the project, leading to a final investment decision by the end of 2005. First electricity production will commence during 1H2009.**

## *Japan secures Taiwanese LNG deal*

Ishikawajima-Harima Heavy Industries and Toa Corporation of Japan, together with Taiwanese engineering firm CTCI are reported to have secured an order to design and construct an LNG receiving terminal in Taichung port, north Taiwan, from Chinese Petroleum Corporation. The terminal is scheduled to be commissioned in January 2008.

CPC and Taiwan Power have a 25-year LNG supply agreement, under which CPC will start feeding gas to Taiwan Power's new 4,272-MW Tatan power plant from the LNG terminal in northern Taiwan starting in 2011. CPC will supply 1.68mn t/y of LNG to Taipower under the deal and has committed to lifting 3mn t/y of LNG from the RasGas II project to supply Taipower's Tatan requirements.

## Transneft's priority pipeline projects

Transneft has announced its list of priority projects, reports UFG. The list includes:

- Expansion of the Baltic Pipeline System (BPS) from 840,000 b/d to 1mn b/d and, upon approval by the government, expansion to 1.24mn b/d by 2006.
- The Western Siberia to Barents Sea pipeline, which would accommodate crude export deliveries from both Western Siberia and Timan-Pechora. Transneft is proposing that the pipeline be constructed to reach the port of Indiga, rather than Murmansk. This would reduce its length from 3,900 km to 1,700 km and, consequently, the cost – from \$9bn–\$15bn to \$5.9bn.
- The Taishet-Nakhodka pipeline in the Russian Far East, which would cost an estimated \$16.22bn. A feasibility study for the project was to be completed in July 2004 and will later be submitted to the government.
- A pipeline around Bosphorus and the Dardanelles, which would cost an estimated \$900mn. According to Transneft, the economics of this pipeline's transportation would be comparable with those of tanker transportation through the Turkish straights.
- The Druzhba-Adria pipeline, which would deliver Russian crude to the Croatian deepwater port of Omisalj for potential VLCC deliveries to markets outside the EU.

## Pearl of a gas-to-liquids project

**Qatar Petroleum (QP) and Shell have signed an integrated development and production sharing agreement (DPSA) that provides for the fiscal and legal terms for the Pearl GTL project in Qatar.**

**The Pearl GTL project comprises the development of upstream gas production facilities as well as an onshore GTL plant that will produce 140,000 b/d of GTL products as well as significant quantities of associated condensate and LPG. The project will be developed in two phases, with the first phase operational in 2009 and producing around 70,000 b/d of GTL products. The second phase is to be completed less than two years later. The project includes the development of a block within Qatar's vast North field gas reserves.**

# In Brief

***Daniel Sanders, President, ExxonMobil*** *Chemical Company, and Vice President, ExxonMobil Corporation, will retire on 31 August 2004. It is anticipated Michael Dolan will be elected as his successor.*

### *Middle East*

***ExxonMobil and the Government of*** *Qatar have entered into a Heads of Agreement (HoA) for a \$7bn, gas-to-liquids (GTL) project at the Ras Laffan Industrial City in Qatar. It is claimed that the 154,000 b/d capacity facility would be the world's largest single, fully integrated GTL project.*

### *Russia & Central Asia*

***Lukoil is to buy from Eni its 50%*** *interest in LukAgip.*

***DEPA of Greece is reported to have*** *reached agreement with Turkish company Botas to start buying 750mn cmly of gas produced at the Shakh Deniz field in Azerbaijan from 3Q2006, rising to 3bn cmly by 2010.*

***Yukos shareholders are understood to*** *have elected State Duma Deputy Viktor Gerashchenko to the Board of Directors. Simon Kukes has resigned as Yukos CEO. He will be replaced by the current COO Steven Theede, but remain as an advisor.*

### *Asia-Pacific*

***Itochu Corporation (20%), Oman*** *Shipping Company (60%) and Mitsui OSK Lines (20%) are understood to have signed a shareholders' agreement for the joint ownership of Oryx LNG Carrier, an LNG vessel operator. Itochu is also reported to have signed an LNG sale and purchase agreement with Qalhat LNG, under which Itochu will purchase 700,000 t/y of LNG over 20 years from 2006.*

### *Africa*

***BG Group has signed a long-term*** *agreement with Equatorial Guinea LNG Holdings (EGLNG) to purchase 3.4mn t/y of LNG for a period of 17 years, beginning in late 2007, from the LNG liquefaction plant being developed by EGLNG on Bioko Island, Equatorial Guinea. Feedstock gas for the project will be sourced from Marathons offshore Alba field.*

# In Brief

## UK

***Toyota and Shell Gas & Power have** launched a trial of Shell gas-to-liquids (GTL) fuel in a fleet of ten Toyota Avensis cars equipped with D-CAT emission reduction technology. Visit* **www.shell.com/gtl/toyota-trial** *for more details.*

***The 28th Shell Eco-Marathon was won** by Microjoule, the French team from St Sebastien, who achieved an outstanding average fuel consumption of 9737 miles per gallon (mpg), some 2,000 mpg more than their closest rival.*

***Over the next decade some $18bn of** capital investment is forecast to be made in large-scale biomass power plants, according to* The World Biomass Energy Report 2004–2013, *a new study published by energy analyst Douglas-Westwood. For further information, visit* **www.dw-1.com**

***ChevronTexaco's Pembroke Refinery** in southwest Wales has processed its first shipment of Doba crude from the oil fields of Chad in Africa, following completion of a $12.8mn project to enable the plant to run the crude. Doba crude is a heavy, acidic blend similar to the North Sea crude oil currently refined at Pembroke, but with a higher calcium content, some 250 ppm.*

## Europe

***France has just opened the greater** part of its industrial and commercial (I&C) market, Germany is getting its regulator and the new EU states are seriously contemplating market liberalisation in 2006/2007. Yet, in many European markets, 'competition' has been viewed as little more than a concept. However, a survey of senior executives in small utilities (average size: 126,000 customers) across Western and Central Europe, conducted by the independent market analyst Datamonitor, has revealed that 71% are worried about competition from large national utilities. Only 34% believe they can survive without the need to grow.*

***Oiltanking recently acquired Union** Carbide's terminal in Texas City, Texas. The 340,000-cm terminal, which will be renamed Oiltanking Texas City, handles petroleum products, gases and chemicals.*



# Future road fuels – the options

The UK Petroleum Industry Association (UKPIA) has published a *Future Road Fuels* report that examines the options for low carbon road fuels and technology in the 21st century. Launching the report at a panel discussion in London in June, Ken Rivers, UKPIA's President, commented: 'The UK oil industry recognises the need to reduce $CO_2$ emissions from road transport – indeed cleaner fuels have the potential to help more efficient conventionally fuelled vehicles meet all of the $CO_2$ reductions expected from UK road transport by 2020. However, looking towards 2050, there are many routes to achieving the government's targets for lower carbon emissions and there is a danger in prematurely picking winners from amongst new fuels or technologies.'

He continued: 'The near-term options include improved vehicle efficiency, traffic reduction measures, conventional biofuels and, in the future, advanced biofuels and hydrogen used in fuel cell vehicles. Consumer behaviour is also likely to be a significant factor, both in choice of vehicle and fuel. To date consumers have tended not to take up new cleaner fuels if they cost more than existing ones.'

Looking at the wider perspective for crude oil supplies, the report highlights that oil, although a finite resource, is not running out and the worldwide reserves of conventional crude oil and non-conventional sources, such as tar sands, are sufficient to meet transport energy needs for at least the next 50 years.

Copies of the report are available in pdf format from **www.ukpia.com** under 'Publications'.

# Respol YPF buys Shell Portuguese assets

**Repsol YPF is to buy Shell's marketing and logistics assets in Portugal, excluding its LPG and lubricants business. This deal includes the acquisition of 303 service stations and increases Repsol YPF's annual petroleum product sales by 1.85mn cm.**

**The agreement, to be completed once regulatory clearance has been obtained, includes most of Shell's business activities in Portugal, such as direct sales for fuels and bitumen, as well as for marine fuels. The operation is significant, since it includes the incorporation of Shell's storage terminals, the purchase of a 15% stake in logistics company Compañía Logística de Combustibles (CLC), and access to a portfolio of storage and logistics.**

**Following the deal, Repsol YPF will see a four-fold increase in the number of its service stations in Portugal to a total of 417. It will become the third largest fuel retailer in the country, with a 19% share of the market. In terms of direct petroleum product sales, Repsol YPF will have a 21% market share of supply, becoming the second-ranked company, and increasing total sales in Portugal by 1.85mn cm to more than 2,500,000 cm.**

# *New gas exchange to be developed at Zeebrugge hub*

APX, Endex and Fluxys subsidiary Huberator have signed a cooperation agreement to develop a gas Exchange at the Zeebrugge Hub in January 2005. The cleared products and services offered are expected to boost both the liquidity and the transparency of the Zeebrugge market and to further strengthen the importance of Zeebrugge in the European gas business.

The Zeebrugge Gas Exchange will be an online, screen-based electronic trading platform (initially for the short-term market only) and offer both physical and financial products. Physical products will include cleared day-ahead and within-day gas trading, as well as some other short-term products.

Financial products will be offered with the possibility of physical delivery and will include in a first phase clearing for long-term over-the-counter deals. The exchange of traded forwards and futures will be added in a second phase.

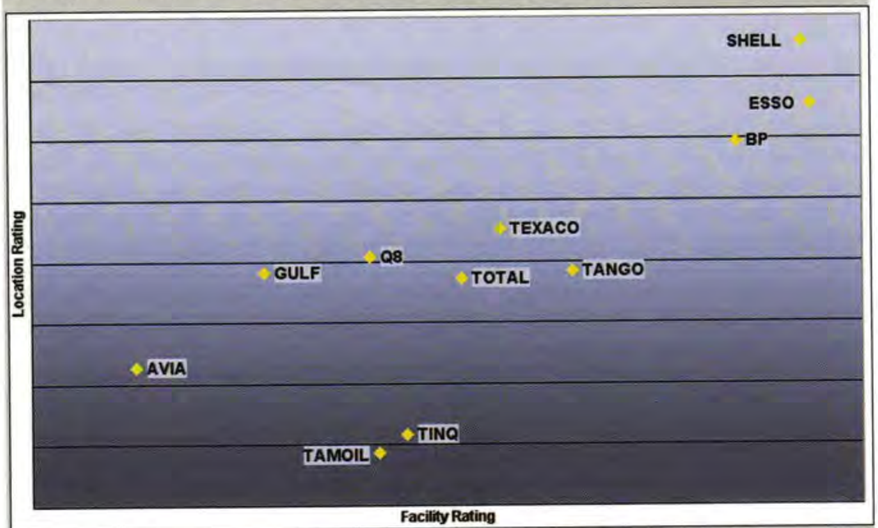
APX and Huberator are to set up a joint-venture for the electronic trading platform. APX will operate the platform and provide clearing, while Huberator will facilitate interfaces between the platform and the Huberator system for physical deliveries. Both the platform and the products will be developed in consultation with the Zeebrugge trading community. Fluxys will take a participation in Endex, which is to set up a separate division for offering clearing services and other financial products.

# Relative strengths of fuel retail brands

In last month's *Petroleum Review* we looked at the competitive positioning of some major brands in the UK. This month it is the turn of the Netherlands. As previously described, the analytical process used here gives the average location and facility strengths for all sites by brand, company owned and dealer owned. 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, site size, site quality, site layout).

Not surprisingly, Shell, Esso and BP lead the pack on both factors, yet there is quite a clear differentiation between the three in respect of location strengths. There is then quite a jump down in terms of location strengths to the second group, but amongst these there is a spread of facility strengths. Tango sites are new and fewer in number than the others but, nevertheless, they are concerned about facility quality. Obviously they are leveraging the competitive price position to make up for the poorer location strengths in comparison to some of the others. TINQ, however, with its similar offer to Tango, is quite significantly disadvantaged on both fronts.

*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.*

# Firsts for Alberta cogeneration power plant

Talisman Energy has started construction of a 10-MW cogeneration power plant at its Edson natural gas processing facility. The $21mn plant is claimed to be the first cogeneration facility at a sour gas processing plant in Alberta and the first retrofit of an existing gas plant to cogeneration.

The new cogen facility will replace older equipment with cleaner, more efficient technology. In addition to reducing the amount of natural gas needed to operate the processing plant by about 12%, or 700,000 cf/d, the new cogeneration power plant will produce about 2 MW of electricity more than is required to operate the gas plant. This is approximately enough additional electrical power to serve 1,000 homes.

The cogen project will also result in the reduction of direct carbon dioxide emissions by 22,000 t/y and a further indirect reduction of 82,000 tonnes annually. Construction is expected to be completed by the end of 2004.

The Edson facility, which now processes about 200mn cf/d of gas, is the largest gas plant operated by Talisman in Canada. It is connected to about 500 km of pipelines within the company's 100% owned Central Foothills Gas Gathering System, Columbia Minehead Gas Gathering System and other midstream pipeline assets ranging from 75–100% ownership that support exploration and development in both the Edson and Foothills areas.

# In Brief

***OMV has acquired the remaining half*** *of shares in Slovenian fuel retailer OMV IstraBenz Holding, which will now become a wholly-owned subsidiary of OMV.*

***The Danish Competition Advisory*** *Board has passed Statoil's takeover of the Haahr service station network, making Statoil the second largest fuel retailing brand in Denmark.*

***Eni has approved the partial division of*** *Italgas, with assignment to Eni of the shareholding held by Italgas in the Italian companies that commercialise gas (including the 100% shareholding in Italgas Più) and foreign companies (including 40% in Tigaz), as well as the merger of Italgas Più in Eni. Turin-headquartered Italgas will continue to manage the entire distribution network.*

## North America

***Atmos Energy is reported to have*** *acquired TXU Gas for $1.925bn, creating North America's largest distributor of natural gas, serving 3.1mn customers in 12 states.*

***ChevronTexaco has begun marketing*** *gasoline in the US under the Texaco retail brand and expects to be supplying more than 1,000 locations in southern and eastern states by the end of the year. As part of its 2001 merger agreement, ChevronTexaco agreed to licence the Texaco retail brand to Shell in the US for the marketing and sale of gasoline on an exclusive basis until 1 July 2004. The companies will now share the brand rights for a two-year transition period until ChevronTexaco regains exclusive rights to the Texaco brand in the US on 1 July 2006.*

***Shell is to sell its Midwest US refined*** *product pipeline system and storage assets in the US to Buckeye Partners for $530mn. This follows the earlier sale of Shell's Texas and Great Plains product pipeline and storage assets in the US for $492mn.*

## Middle East

***Aramco Overseas Company, a sub****sidiary of Saudi Aramco, is to acquire from Shell a strategic 50% shareholding in Japanese refining and marketing company Showa Shell.*

***Ofer Brothers and British Gas are*** *understood to be proposing to con-*

*struct and operate a private power station that would create electricity from natural gas at the Ashkelon plant in Israel at an estimated cost of between $200mn and $250mn. It is understood that the opening of a third power station (in addition to those at Mishor Rotem and Ramat Hovev) will provide British Gas with the required 1,200 MW of demand to make the development of gas fields in Gaza economically viable.*

### Asia-Pacific

***China National Offshore Oil** Corporation (CNPC) is reported to have secured a licence to import diesel and other oil products into China, placing it in competition with Sinopec and PetroChina, which currently account for 95% of fuel sales in the country.*

***ChevronTexaco's wholly owned sub**sidiary Caltex Singapore has acquired half of BP Singapore's one-third equity interest in the Singapore Refining Company (SRC) to become a 50/50 joint owner in the refinery with the Singapore Petroleum Company (SPC).*

### Latin America

***Shell is proposing to sell its Peruvian** service station network and industrial and marine fuels businesses. It will retain its lubricants business in Peru.*

***Eni is to sell to Petrobras the entire** stake of Agip do Brasil for $500mn. Agip do Brasil is involved with LPG sales and operates a network of about 1,500 petrol stations in Brazil.*

# UK gas and electricity markets

Electricity blackouts in the US and Europe last year, along with the realisation that the UK's self-sufficiency in gas will soon be over and the weak financial health of the electricity sector, has ensured that energy security of supply has become a major policy issue, reports analyst Wood Mackenzie. 'The UK gas and electricity sectors face a number of key challenges, including imminent and steadily increasing gas import dependency, carbon emissions trading from 2005, tightening sulphur emissions limits in 2008, and the closure of most existing nuclear power stations by 2015.'

Against this background, Wood Mackenzie has undertaken a study of the UK gas and electricity markets, entitled *From Surplus to Shortage?* 'By 2015 Wood Mackenzie expects that the UK will be almost 75% dependent on gas imports, rising to 90% by 2020,' says Project Director Stewart Gray. 'This requirement will be met from a range of sources and transport routes, including Norwegian, Dutch and Russian piped gas and LNG from (probably) Algeria, Egypt and Qatar.'

'Within the power generation sector, gas will account for almost 75% of output in 2015, a share which will be maintained out to 2020. Meanwhile, renewables will make significant progress towards, and will only narrowly miss, the government's target of 10% by 2010, but in the longer term growth will slow as the easier opportunities are taken up.'

One of the key issues addressed in the study was the outlook for security of supply in gas and electricity. Gray says: 'We concluded that gas and electricity security of supply should be maintained, out to 2010 even in severe winters, although this will require substantial pipeline imports from Europe, and extensive use of generation fuel switching and managed interruption of industrial gas demand. Between 2005 and 2010 the security of supply situation should actually improve, as the various projects for new gas supply capacity – pipeline, LNG and storage – are brought into operation. Beyond 2010, however, the study identified that the UK would need additional "strategic" gas supply flexibility, in the form of seasonal storage or equivalent alternatives, in order to meet extreme cold winter conditions.'

Wood Mackenzie believes that the regulatory authorities will need to maintain a watch on the market to determine whether they will actually deliver the gas supply capacity needed. 'Vigilance will be needed,' says Gray. 'One of the key corporate issues will be whether the UK's six large integrated utilities will be prepared to sign the large, long-term contracts needed to underpin the necessary developments.'

The study also examined the outlook for future wholesale gas and electricity prices. The largest single influence on gas pricing in the UK is likely to remain the Continental European gas price and thus, via the indexation mechanism contained in the principal European gas contracts, the oil price. 'This oil linkage would be weakened or removed if gas-to-gas competition were to break out in Europe, but despite the European Commission's best efforts, this has to be seen as a less than likely possibility,' says Gray.

**UK Deliveries into Consumption (tonnes)**

| Products | †May 2003 | †May 2004 | †Jan–May 2003 | †Jan–May 2004 | % Change |
|---|---|---|---|---|---|
| Naphtha/LDF | 130,147 | 182,829 | 986,881 | 1,028,291 | 4 |
| ATF – Kerosene | 841,714 | 906,095 | 3,989,356 | 4,099,597 | 3 |
| Petrol | – | – | – | – | – |
| of which unleaded | 1,626,453 | 1,607,421 | 7,925,143 | 7,940,010 | 0 |
| of which Super unleaded | 65,026 | 75,978 | 330,423 | 346,196 | 5 |
| ULSP (ultra low sulphur petrol) | 1,561,427 | 1,531,443 | 7,594,720 | 7,593,814 | 0 |
| Lead Replacement Petrol (LRP) | 18,475 | \5,838 | 96,725 | 35,061 | –64 |
| Burning Oil | 268,114 | 265,570 | 1,922,023 | 2,164,439 | 13 |
| Automotive Diesel | 1,461,063 | 1,532,008 | 6,977,712 | 7,689,606 | 10 |
| Gas/Diesel Oil | 476,664 | 538,959 | 2,576,466 | 2,685,982 | 4 |
| Fuel Oil | 157,779 | 262,841 | 962,342 | 1,090,363 | 13 |
| Lubricating Oil | 68,181 | 65,170 | 351,022 | 320,120 | –9 |
| Other Products | 639,907 | 784,509 | 3,279,738 | 4,166,048 | 27 |
| Total above | 5,707,497 | 6,151,241 | 29,087,378 | 31,219,518 | 7 |
| Refinery Consumption | 380,275 | 473,105 | 1,984,843 | 2,132,792 | 7 |
| Total all products | 6,087,772 | 6,624,346 | 31,072,220 | 32,875,237 | 6 |

† Revised with adjustments

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

# European storage takes a back seat

A4S terminal, Antwerp

**Increasing world trade in liquid hydrocarbons and chemical products continues to underpin growth in demand for, and investment in, terminalling services around the world. Developments in Europe have, by contrast, generally been low key. *Petroleum Review* reports.**

Europe's independent bulk liquids storage terminal operators are mostly having a comparatively poor 2004. While utilisation remains at generally high levels, throughput has been slower, especially for petroleum products. And the major international terminal operators are concentrating investment activity in more exciting territories, especially in China. Compliance with new regulations, particularly on the security side, has also drawn management time and attention away from new construction activity.

In addition, there has been some restructuring going on in the industry itself over the past two years, involving many of the big names in the business. Vopak's decision in mid-2002 to spin off its chemical distribution activities as a separate company, Univar, left it assuming most of the group's debt and put a temporary brake on activity during 2002 and the first half of 2003.

Since then, however, the world's largest independent terminal operator has come back aggressively. In Europe, it is currently converting tankage at the Europoort facility in Rotterdam from crude oil to fuel oil and adding additional berths. Work is expected to finish later this year at a cost of 10mn. New tanks are being added at the Vlaardingen site, which specialises in vegetable oils. Meanwhile, additional capacity is going in at the joint-venture Pakterminal facility in Estonia, where the partners have bought three existing tanks from the neighbouring Transoil terminal and have announced plans to build further tanks to meet growing local demand. Vopak appears keen to expand its operations in eastern Europe, but attempts earlier this year to buy into the Polish oil and chemical distribution network through a deal with Naftobazy failed.

These projects pale into insignificance, however, beside Vopak's activities elsewhere in the world. Most notable is the Caojing project in China, which is being built to handle anticipated demand from the massive new petrochemical facilities under construction near Shanghai. The first phase of the 200,000-cm, $200mn terminal should be onstream before the end of this year. Last September Vopak bought out Shell's 50% interest in the Tianjin terminal, which is scheduled to be expanded from its existing 20,000 cm capacity to 100,000 cm over the next three to five years. Vopak is also putting

$33mn into a new oil products terminal in Darwin, Australia, as part of an agreement with the major oil companies in the country, and also has projects lined up in Thailand (at Map Tha Phut) and Singapore, where it is building a fourth terminal in the Banyan sector of Jurong Island.

## All around the world

Vopak's only serious competitor in terms of global reach and overall tank capacity is Oiltanking, part of the Marquard & Bahls group. Oiltanking's main project in Europe is the new terminal at Terneuzen, which is being built to serve a 15-year contract with Dow Chemical's De Mosselbanken facility. The first phase, of 156,000 cm, is due for commissioning around the end of this year and will provide some 12,000 cm of for-hire capacity for third parties. Oiltanking is investing some 60mn in this first phase and has chosen to use the new 'cup tank' design – basically a tank-within-a-tank arrangement – to avoid the need for other secondary containment measures and so save on space. Current plans are to expand the terminal's capacity to 335,000 cm in a second phase.

Elsewhere in Europe, Oiltanking has expanded capacity at its Amsterdam and Antwerp terminals and has embarked on further expansion of chemical tank capacity at Antwerp, where 67,500 cm of new tankage is coming onstream gradually over the period to 2006, again using cup tanks. The company has completed a significant expansion in Houston, but two other major projects are in Asia, both in partnership with Odfjell. Fifteen new tanks were added at the OOTS terminal in Singapore last year, bringing capacity up to 213,000 cm, and there is space to expand this to 300,000 cm. More excitingly, however, Oiltanking and Odfjell have each taken a 35% holding in a 22,000 cm liquids terminal at Bandar Imam Khomeini in Iran, which is due to open for business by the end of next year. Initially, at least, the facility is expected to be used as an import and distribution point for chemicals, but there is land available to expand capacity to 100,000 cm and the terminal's role could well change if Iran's fledgling petrochemical sector develops at the rate anticipated.

Odfjell itself recently announced plans to build an 80,000 cm tank terminal at Jiangyin on the Yangtse River in China, in partnership with the local Garson Group. The $30mn facility will have ample land for expansion, Odfjell says.

Another operator with an increasingly international presence is ST Services, which is in the process of being rebranded Kaneb Terminals (it is a subsidiary of Kaneb Pipe Line Partners). Originally focusing on the US market, ST has expanded through acquisition across North America and the Caribbean, into the UK (buying the GATX sites) and at the end of last year into Australia and New Zealand, when it bought Terminals Pty Ltd, the largest provider of independent storage capacity in the region. This latest move has also taken the company more deeply into the chemicals sector as, until now, only the Texas City, US, and Eastham, UK, terminals have been primarily chemicals sites. Eastham has recently enjoyed a small expansion with the addition of a new tank dedicated to handling ethylene dichloride for Ineos Chlor.

## Focus on Europe

The restructuring process has affected two of the largest European terminal networks – LBC and Simon Storage. One Equity Partners, the private equity arm of Bank One Corporation/JP Morgan Chase & Co, bought LBC from its former owner Fimalac in May of this year for an undisclosed sum. The management has remained in place and says that the financial backing of the new owners will allow LBC to develop its existing network of 12 terminals in Europe and the US. [At the time of writing, however, no developments had yet been announced.]

Similarly, Simon Storage was bought from the Simon Group by Siena Investments, a subsidiary of Patron Capital, at the start of 2003. The £88mn deal included Simon's wholly owned storage terminals in the UK, together with the 49.99% shareholding of Vopak in the five joint-venture terminals, as well as Simon's chemical logistics, facilities management, engineering, automation and training operations under the Simon Network banner. As with LBC, the management remained in place and expressed itself happy to have access to funding for expansion.

However, since the buyout very little has happened at Simon. Its new investor will obviously be looking for a significant return but there is little room to expand within the UK and Simon will have to look elsewhere if it is to make an acquisition or invest in greenfield sites. In June of this year, however, Simon announced it had won a 30-year contract to handle biodiesel at its Seal Sands terminal on Teesside in northeast England on behalf of Biofuels Corporation, a new company set up to build and operate one of Europe's largest biodiesel production facilities on land owned by Simon. Once the plant comes onstream next summer, Simon expects to handle up to 250,000 tonnes of raw materials per year. This will include both domestic and imported vegetable oils. The announcement seems timely, since other proposed investments in the Teesside region have come to nought and some terminal operators in the region have privately expressed concern that the petrochemical industry is in decline.

Petroplus, the midstream oil company that operates a number of independent oil terminals, has also been the subject of equity investment. In June this year the Board recommended a cash offer for all oustanding shares from RIVR Aquisition, part of the Carlyle Group. The deal, which is unlikely to close before the end of August, values the company at some 247mn.

One of the more interesting projects announced this year in Europe came from PIR, the Italian terminal operator based in Ravenna. The privately owned company is to establish a subsidiary – Petrolifera Italo Albanese (PIA) – in Tirane, Albania, to develop, build and operate a bulk oil, chemical and LPG terminal at Vlora Bay. The 43,000-cm (including 6,000 cm for LPG) terminal is scheduled to come onstream by the end of 2006 at a cost of some 30mn, including dedicated port infrastructure. The location has been chosen because of its excellent transport links into the southern Balkans, PIR says. The company is also expanding and rationalising its Ravenna terminals after spending the last few years improving rail links to its market hinterland.

*continued on p16...*

# Independents assuming greater prominence in US energy scene

**Major oil companies are selling US onshore and offshore oil and gas fields that have unproduced reserves but low-profit margins in order to focus on riskier, but potentially more profitable, international projects. Independents with experience in reworking older and smaller fields, and with lower fixed costs than the majors, are buying up these divestments. *Judith Gurney* reports.**

Following its 'big field' strategy of concentrating investment in potentially huge reservoirs, BP has sold a number of its US assets to Apache. ChevronTexaco has declared its intention to sell a large proportion of its involvement in US gas projects, mostly non-operated joint ventures and coalbed methane operations, in order to focus on international gas projects. Anadarko, one of the largest US independents, has also adopted a big-field strategy, which involves selling mature onshore US oil and gas properties and focusing on high-risk, high-reward overseas projects, such as in Qatar and Algeria. However, like most major companies, it is continuing to retain its interests in its deepwater Gulf of Mexico projects.

This shifting in ownership has resulted in a stronger role in the US domestic oil and gas industry of independents such as Kerr-McGee, Magnum Hunter, Remington, Pioneer, Dominion, Devon, and Pogo. Independents are bidding for blocks believed to hold smaller fields in Alaska and they are heavily involved in projects in the Rocky Mountains and in the Gulf of Mexico. Historically, major companies made the majority of Gulf discoveries and led the movement into deeper waters. Currently, the number of new Gulf discoveries by independents is surpassing that of majors, and several of these finds are in ultra-deep waters.

| Project | Operator | Area | Water depth (metres) | Discovery year |
|---|---|---|---|---|
| Aconcagua | Total | MC | 2,250 | 1999 |
| Camden Hills | Marathon | MC | 2,296 | 1999 |
| Blind Faith | ChevronTexaco | MC | 2,170 | 2001 |
| Merganser | Kerr-McGee | AT | 2,459 | 2001 |
| St Malo | Unocal | WR | 2,234 | 2001 |
| Trident | Unocal | AC | 2,993 | 2001 |
| Cascade | BHP Billiton | WR | 2,483 | 2002 |
| Great White | Shell | AC | 2,264 | 2002 |
| Vortex | BHP Billiton | AT | 2,568 | 2002 |
| Atlas | Anadarko | LL | 2,798 | 2003 |
| Chinook | BHP Billiton | WR | 2,776 | 2003 |
| Jubilee | Anadarko | AT | 2,711 | 2003 |
| Spiderman/Amazon | Anadarko | DC | 2,470 | 2003 |

Areas: AC = Alaminos Canyon, AT = Atwater Canyon, DC = DeSoto Canyon, LL = Lloyd Ridge, MC = Mississippi Canyon, WR = Walker Ridge

*Source: US Department of Interior Minerals Management Service*

Table 1: Gulf of Mexico discoveries in water depths greater than 2,160 metres – to end-2003

## Major focus on LNG

Most majors are keeping a US presence based on ongoing and planned deepwater and ultra-deepwater projects in the Gulf of Mexico. Some are seeking involvement in the construction of LNG import terminals as outlets for their overseas gas production. ChevronTexaco hopes to build two offshore LNG terminals – Port Pelican in the Gulf, which seems likely to be realised, and another off the coast of Baja, California, which will probably never be approved. ExxonMobil, Shell and BP have also announced proposals for onshore and offshore LNG terminals.

The Gulf of Mexico is the site for most LNG terminal proposals as it provides existing infrastructure for the transport of gas to the northern and eastern US markets and offers less opposition to terminal construction. Independent companies, however, are concerned that the majors will be able to set aside shipping channels for the delivery of LNG from offshore terminals that will hinder the development and production of their Gulf holdings.

It would be more profitable to locate terminals closer to markets in New York, New England and California. But local opposition to terminals in these areas is strong and has increased since the January explosion at Algerian LNG facilities. Three projects were cancelled due to local opposition this spring – one in Harpswell, Maine, proposed by partners ConocoPhillips and TransCanada; one in Baja, California, proposed by Marathon; and one in Humboldt, California, proposed by Calpine.

## An illusive energy bill

One reason for the reduced enthusiasm of major oil and gas companies is undoubtedly discouragement over the inability of the federal government to open up areas off the coasts of California and Florida and in the Arctic

National Wildlife Refuge (ANWR) for oil exploration and production; to relax restrictions on operations in the Rocky Mountains; and to insure financial support for an Alaskan gas pipeline.

Both houses of Congress have been considering one version or another of a comprehensive energy bill for more than three years, unable to come up with a compromise on the above key issues as well as regarding protection from liability for producers of the gasoline additive methyl tertiary butyl ether (MTBE) and an overall price tag.

The impending congressional and Presidential elections are partly to blame for this year's gridlock. Politicians seeking votes from the Midwest farm states insist on a mandate for the use of corn-base ethanol as an additive in reformulated gasoline, and those seeking votes in states with oil interests demand a liability waiver for producers of MTBE. Some Republicans hope that their party will gain enough Congressional seats in November to enact an energy bill that includes ANWR leasing next year. President Bush is playing it safe and avoided mention of an energy bill in his annual State-of-the-Union speech last January.

It isn't as if there aren't serious energy problems that the government needs to address. Unusually high natural gas prices have prevailed for almost two years, with domestic production increasingly unable to meet demand. Output from the onshore and offshore Gulf of Mexico is falling by 8% to 10% a year and most reserve discoveries are extensions of existing fields. There is potential for increased output from the Rocky Mountains, but 80% of its resource base is unconventional – tight gas, coalbed methane and shale – presenting technical and non-technical challenges for finding and producing.

The unusually high gasoline prices this summer are not entirely due to elevated crude prices worldwide. Federal and state environment regulations encouraging regional markets and discouraging refinery construction (US refineries are currently running at an average of 96% of capacity) are contributing factors which government action could alleviate. And finally, the massive power failure last August, which blacked out the northeast US and southwest Canada, clearly demonstrates the need for reforms of the electrical power distribution system.

In late spring the Senate attached provisions calling for nearly $19bn in energy tax incentives, including Alaska pipeline support that involved a price subsidy, to a corporate tax bill. It is questionable if any, or all, of these provisions will be accepted by the House and therefore enacted into law.

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| 2 Jan | 6.31 | 5.04 | 2.39 |
| 9 Jan | 7.03 | 5.13 | 2.23 |
| 16 Jan | 6.28 | 5.36 | 2.29 |
| 23 Jan | 5.33 | 5.52 | 2.07 |
| 30 Jan | 5.56 | 5.54 | 2.05 |
| 6 Feb | 5.53 | 5.81 | 2.13 |
| 13 Feb | 5.40 | 5.84 | 2.25 |
| 20 Feb | 5.28 | 6.20 | 2.41 |
| 27 Feb | 5.23 | 8.69 | 2.37 |
| 5 Mar | 5.48 | 7.01 | 2.62 |
| 12 Mar | 5.49 | 5.82 | 2.98 |
| 26 Mar | 5.45 | 5.31 | 3.29 |
| 2 Apr | 5.72 | 5.14 | 3.38 |
| 16 Apr | 5.86 | 5.02 | 3.46 |
| 19 Apr | 5.78 | 5.25 | 3.19 |
| 23 Apr | 5.57 | 5.65 | 3.44 |
| 30 Apr | 5.87 | 5.57 | 3.43 |
| 7 May | 6.26 | 5.69 | 3.70 |
| 14 May | 6.37 | 6.17 | 3.70 |
| 21 May | | 6.08 | 3.43 |
| 28 May | | 6.04 | 3.28 |
| 7 Jun | | 6.44 | 3.24 |
| 14 Jun | | 6.03 | 3.18 |
| 21 Jun | | 5.75 | 3.29 |
| 28 Jun | | 5.59 | 3.33 |
| 4 Jul | | 5.29 | 3.16 |
| 11 Jul | | 5.36 | 2.88 |
| 18 Jul | | 5.03 | 2.87 |
| 25 Jul | | 4.86 | 2.94 |
| 1 Aug | | 4.72 | 2.90 |
| 8 Aug | | 4.83 | 2.71 |
| 15 Aug | | 5.05 | 3.03 |
| 22 Aug | | 4.94 | 3.34 |
| 29 Aug | | 4.81 | 3.39 |
| 5 Sep | | 4.73 | 3.23 |
| 12 Sep | | 4.77 | 3.36 |
| 19 Sep | | 4.60 | 3.70 |
| 26 Sep | | 4.55 | 3.79 |
| 3 Oct | | 4.77 | 3.97 |
| 10 Oct | | 5.27 | 3.90 |
| 18 Oct | | 5.38 | 4.26 |
| 25 Oct | | 4.85 | 4.14 |
| 31 Oct | | 4.61 | 4.18 |
| 7 Nov | | 4.74 | 3.87 |
| 14 Nov | | 4.85 | 3.88 |
| 21 Nov | | 4.72 | 4.28 |
| 28 Nov | | 4.89 | 4.20 |
| 5 Dec | | 5.82 | 3.64 |
| 12 Dec | | 6.83 | 4.82 |
| 21 Dec | | 6.28 | 5.22 |
| 28 Dec | | 6.30 | 5.05 |

*Source:* Oil & Gas Journal

**Table 2: US natural gas futures prices $/mn Btu**

## Gulf of Mexico prospects

There is concern that the majors may in fact also be losing long-term interest in the offshore Gulf of Mexico. There is little to attract them in Gulf shallow waters, where output decline is well documented. Oil production is now at levels lower than those of the mid-1960s, with output in deep waters able to make up for most of this loss so far.

Not so for gas, as gas production from deepwater fields has not been able to compensate for the shallow-water output decline to date. Optimism has faded somewhat regarding the potential of substantial, undiscovered ultra-deep gas reservoirs in shallow waters in the face of the few recent finds and widespread uncertainties regarding the industry's ability to map or drill ultra-deep fields.

What is causing some alarm is that enthusiasm for Gulf deepwater exploration seems to be waning in the face of unspectacular recent discoveries and slow output growth. The US Minerals Management Service (MMS), which manages offshore federal properties, acknowledges concerns about deepwater operations. In a recent report, the MMS noted that although deepwater production and the number of discoveries increased substantially in 2002 and 2003 'some measures of deepwater activity have declined'. It cited decreases in the average bid amount per block, the average number of rigs operating, the number of wells drilled and the number of development plans submitted to the MMS.

Close to two-thirds of the 90 deepwater projects in production at the beginning of 2004 came onstream in the 1990s. Some analysts are disturbed by what they consider to be a slow increase in deepwater production in view of the fact that subsea tiebacks to existing production hubs in shallow waters facilitate the easy and relatively cheap development of deepwater projects. Except for the occasional TLP and spar, subsea systems are the overwhelming favourite for deepwater fields, accounting for three-quarters of the developments since 1999. However, one hazard of dependence on subsea tiebacks to existing production hubs is the effect of hub malfunction on the output of multiple projects, as shown recently by the shutdown of the Mars TLP following an oil leak.

On the positive side, the MMS notes that there have been 13 discoveries in ultra-deep waters up to the end of 2003 and that ChevronTexaco, Unocal, Anadarko, BP, Kerr-McGee and Dominion recently have announced both deepwater and ultra-deepwater discoveries. Two deepwater projects came onstream earlier this year – Shell's Llano field in Garden Banks (subsea tieback) and Dominion's Devil's Tower gas field in Mississippi Canyon (spar). Anadarko's Marco Polo field in Green Canyon is expected to come onstream this summer (TLP).

The MMS also points out that there were a record number of deepwater leases awarded in offshore block auctions in the mid-1990s when royalty relief was announced, and that only about 6.5% of the 3,200 deepwater leases issued between 1996 through 2000 had been drilled by the end of 2003. It expects that there will be a lot of interest in acquiring deepwater acreage when these unexplored leases expire soon.

In addition, the MMS notes that while effectively all – some 99 – of total current Gulf offshore production is from Pleistocene, Pliocene and Miocene reservoirs, there have been several recent discoveries in Oligocene, Eocene and Paleocene sands. It is optimistic that the presence of pre-Miocene reservoirs, and significant discoveries in the ultra-deep, demonstrate the continuing exploration potential of the Gulf.

## Outlook for Alaska

Few doubt the continued decline of oil production in Alaska unless the ANWR is opened up for exploration and production. However, in the absence of ANWR opportunities, continued efforts to increase Alaska's flagging oil output are meeting with qualified success. Several companies bid for some of the offshore Beaufort Sea blocks that the MMS offered in a lease sale in late 2003, but no bids were received at a MMS lease auction held this spring for offshore acreage in southern Cook Inlet. Interest continues in onshore acreage in the National Petroleum Reserve-Alaska (NPR-A), an area west of Prudhoe Bay and the ANWR that contains a potentially oil-rich geologic vein. The first NPR-A lease sale, held in 1999 by the US Bureau of Land Management (BLM), the agency that controls federal onshore properties, resulted in discoveries in 2001. A second sale was held in 2002, and a third this past May in which five companies bid. The BLM says that it will make more NPR-A acreage available shortly. Congressional approval is not necessary for NPR-A leasing, but environmental groups are active in opposing the leasing of any acreage in the reserve.

With oil revenues steadily decreasing, the construction of a gas pipeline to enable the production and transport to continental US markets of the estimated 35tn cf to 100tn cf of North Slope natural gas is vital to the future economic well-being of the state of Alaska. Apparently assuming that some measure of federal financial support will eventually be forthcoming, the Alaskan Government has been holding talks with the three leaseholders of North Slope gas fields – ConocoPhillips, ExxonMobil and BP – and with several investment banks. As estimated pipeline costs vary from $7.3bn to $20bn depending on the route, financial aid will be required from multiple financial organisations as well as from the federal government. The Alaskan Government is keeping all options open at this time and is processing applications made by TransCanada for the rights-of-way to construct a gas pipeline across north Alaska into Canada as another solution to enable the production and sale of Alaskan gas.

...continued from p13

Expansions are also being undertaken by Rubis Terminal, a company created in 2002 when CPA's parent Groupe Rubis acquired Propétrol from Pétrofrance. Its 563,000-cm Rouen terminal in northern France has been expanded with the acquisition of the neighbouring Miroline terminal from Total, adding 25,000 cm of petroleum product capacity. Rubis has also been in negotiation with the Port of Antwerp with a view to setting up a new facility on the left bank of the River Schelde. Currently, the only terminal on the left bank is ADPO, although LBC also has approval for a greenfield site. The right bank is now effectively full and any further development at Antwerp – which has successfully positioned itself as the prime chemicals port in northern Europe – will have to take place on the left bank.

## Work for idle hands

The UK Tank Storage Association's (TSA) annual conference, held each May in Coventry, usually provides a barometer of the issues that are dominating the thoughts of terminal operators. At this year's event, talk centred on the continuing impact of the implementation of the EU's Seveso II Directive, which has caught a lot more bulk liquids terminals in its net than did its predecessor directive. It also contains more stringent requirements related to health and safety at work and Martin Anderson of the UK Health & Safety Executive's (HSE) Hazardous Installations Directorate (HID) pointed out that companies in scope of the regulations will have to demonstrate – not just describe – that their procedures are effective. He also reminded delegates that safety levels in the workplace can be badly affected during periods of business reorganisation – something that is a common feature in the terminals industry in Europe at present.

Terminals are also being required to look at the security aspects of their operations. Many sites fall under the provisions of the IMO's International Ship and Port Facility Security (ISPS) Code, which came into effect on 1 July this year. Terminals have to draw up and implement security plans, in cooperation with the port authorities under whose jurisdiction they fall, and appoint security officers. To a large extent this work has already been covered, especially in the oil and chemicals sectors, by voluntary codes and by similar safety-based provisions, but it does present yet another set of reports to be completed and submitted. More work for terminals at a time when European operators are finding good returns on investment hard to come by.

# Towards Zero Carbon: Sustainability in Practice

energy INSTITUTE

*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

in association with

Solar Energy Society

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.

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- David Olivier – Energy Advisory Services
- Professor Sue Roaf – Oxford Brookes University
- Sam Heath – London Renewables
- William Orchard – William Orchard & Partners
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- Louise Kingham – Energy Institute
- Dr Patrick Devine-Wright – De Montfort University
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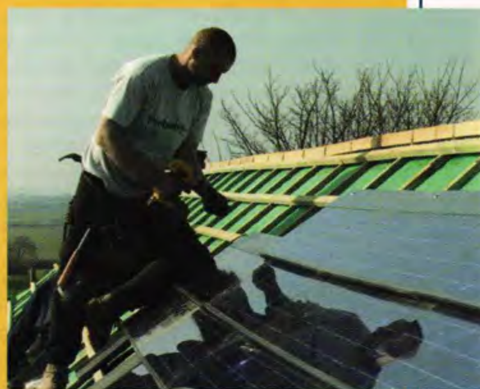

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# Rising gas investments herald LNG/GTL boom

**There has been much talk of gas being the 'fuel of the future'. Here, *Chris Skrebowski* has tabulated all the reported gas megaprojects for LNG and GTL production and concludes that a massive shift to gas is already underway, fuelling an investment boom. The key driver is to monetise the world's abundant gas reserves outside the US and to use them to meet growth in gas demand and shortfalls in North America supply.**

Over the last decade gas demand growth has averaged 2.6%/y, but over the same period LNG trade has averaged 6.4%/y growth. This has been the key driver behind the recent investment boom in LNG projects around the world (see **Table 1**). The global gas market can be divided into five main areas, each of which has defining characteristics. The largest in terms of both the consumption and production of gas is Eurasia, with Russia and increasingly the Central Asia/Caspian region the key pipeline suppliers to the main western European consumption centres. LNG supplies have been a feature of the western European market for many years, but are now set to expand quite rapidly.

The *BP Statistical Review* of June 2004 shows that gas production in the 15 countries of the European Union has fallen for the last two years. Notable declines in 2003 in western Europe were: Italy (–6.0%), Denmark (–5.3%), Romania (–4.4%), the Netherlands (–3.8%) and the UK (–0.9%). Rising demand and the supply shortfalls are set to give a major boost to LNG imports. Already there are actual or planned imports of LNG from Egypt, Nigeria, Trinidad, Qatar and Oman, in addition to the long established imports from Algeria. For the first time Europe will have a local source of LNG with the development of Norway's Snøhvit gas field and associated LNG plant. Similarly, emerging shortfalls in European gas supplies will boost long distance pipeline supplies from sources such as Russia, Algeria, Iran and the Caspian suppliers – Azerbaijan, Turkmenistan, Kazakhstan and possibly Uzbekistan.

Next in size in terms of both consumption and production is the North American market. This is an area where regional supply self-sufficiency is threatened by declining production in both the US and Canada. However, it is the move by the US to becoming a significant importer of gas as LNG that is revolutionising the global gas market.

## Drilling booms

In the last three years declining gas production in North America has stimulated a drilling boom in both Canada and the US. The results have proved particularly disappointing in the US. According to a recent CERA (Cambridge Energy Research Associates) study, the number of wells producing gas in the US increased from about 300,000 in 1999 to over 350,000 in 2001, but average productivity declined from 171,000 cf/d to 145,000 cf/d over that same period. Average well productivity in Canada is also reported by CERA to be declining. Considerable interest has been shown in the Rockies – in both the US and Canada. A number of recent major takeovers of companies with acreage in the US Rockies confirm their potential to boost supplies from the area by increased drilling activity.

A similar drilling boom is now underway in the Canadian foothills to the Rockies. So far the outcome is unclear, with Canadian production still reported to be falling at around 4%/y. Much discussion in the industry centres on the amount of acreage that is sterilised by drilling prohibitions – the most spectacular example being the Destin Dome in the US Gulf of Mexico. Although a known and partially proved gas field, political fears about beach pollution in Florida [a confusion between oil and gas?] have led to a ban on drilling activity or field development. Many other areas are either closed or have restricted access because of environmental concerns despite the current US government's commitment to open up acreage for exploration.

## Blocking new supplies

Similarly, drilling bans on Federal lands and a number of offshore areas are widely blamed within the gas industry for restricting or blocking new supplies. Although there has been some easing of permitting, the impact so far has been limited. As a result, increasing attention has focused on meeting the supply shortfall by LNG imports and by pipelining Alaskan and Mackenzie Delta gas south to the lower 48 states.

Canada now appears set to go ahead with the Mackenzie Delta pipeline, having secured the support of the aboriginal peoples along the 760-mile route of the 1.2bn cf/d, C$5bn pipeline. However, this is unlikely to be completed before 2009/2010. There are already concerns that tar sands development will preempt a large portion of the incremental gas supply – assuming the gas price is low enough relative to the value of burning the tar sands product. In 2003, the three operational oilsands projects spent $520mn on gas, or around five times the amount they had spent in 1999, according to the analyst Peters and Co. While the Mackenzie Delta pipeline now looks a certainty, the larger, longer and much more expensive Alaskan pipeline is more problematic. The US Congress is reluctant to guarantee financing and the companies have fears about cost overruns given their experience with the oil pipeline across Alaska. Even if final sanction is given relatively soon, supplies will not reach the lower 48 until after 2012.

According to the earlier mentioned study from CERA, sponsored by Accenture – *Charting a Path: Options for a Challenged North American Natural Gas Market* – deeply rooted supply and demand trends, regulatory constraints and structural inflexibilities are driving the US toward a crisis in natural gas similar to the crude oil crisis of the 1970s. The study found strong parallels between today's US natural gas industry and the US oil industry of the 1970s, when oil production declined in the face of high oil prices and a surge in drilling.

'Despite historically high natural gas prices and near-record levels of onshore US gas drilling activity, gas production in the United States today continues to fall, and CERA expects ongoing declines of US gas production despite an outlook for continued strong drilling levels,' said Michael Zenker, CERA's Senior Director, North American Natural Gas. 'This inability to grow supply, despite substantial investment, is at the core of the supply dilemma facing North America,' he added.

The CERA study identified several options available to manage the situation, including reducing consumption of natural gas by encouraging fuel flexibility and the use of non-gas fuels in the power sector, promoting conservation through continuous consumer-education programmes, and promoting new supply sources. 'New supplies could come from speeding expansions of existing LNG facilities, encouraging new LNG facilities, boosting domestic supply by streamlining permitting for activity in areas already open for gas production and by applying flexibility in areas with various restrictions,' Zenker said.

Industrial firms in the US have already been struggling with recent price levels. Some are expected to close or mothball plants in the face of seasonal prices rising to between $6.50mn Btu and $8/mn Btu, while others will relocate outside the US to take advantage of lower short-term energy pricing elsewhere. Residential and commercial customers will see higher bills, negatively impacting incomes and the overall economy.

Natural gas currently provides nearly one-quarter of US energy needs, a level that is expected to grow as the latest of a large fleet of new, natural gas-fuelled power plants becomes more heavily used to meet a growing demand for electricity. North America has added 200,000 MW of new power plant capacity over the last five years, double the current US nuclear power capacity. Around 94% of this new capacity is fuelled by natural gas.

Many power plants and industrial firms turned to natural gas as the result of 14 years of low and stable prices at the $2 to $3/mn Btu range. However, in the past 20 months, the natural gas market has seen prices above $4/mn Btu and regional daily gas prices that have broken new records of over $5/mn Btu. CERA forecasts prices to average as high as $6.62/mn Btu by 2007 – even without a severe weather event that could dramatically spike prices. *[In reaction to high gas prices US gas consumption actually fell by 4.9% in 2003, according to the latest* BP Statistical Review, *June 2004. Ed.]*

LNG is already the fastest growing source of supply to the North American gas market. By CERA estimates, North America alone will require about 11bn cf/d of LNG supply by 2010, which would make LNG the third largest supply source for North America. The market is already moving quickly in that direction. A year ago, 13 new regasification terminals were being proposed, now there are over 35, which represents over 30bn cf/d of regasification capacity. By comparison, the US and Canada are expected to consume about 67bn cf/d of natural gas in 2004.

## Focus on LNG imports

As a result, more and more attention is being focused on LNG imports. The four existing LNG import terminals – Everett, Cove Point, Elba Island and Lake Charles – are now fully reactivated and operating close to capacity, although collectively this only represents the equivalent of about 2% of US gas demand.

There are already plans to expand their capacity. Expansion at Cove Point (2005), Elba Island (2005) and Lake Charles (2006) will boost LNG import capacity to a little over 3% of US demand. This, however, is just the beginning. There are two firm new LNG projects – Port Pelican and Freeport LNG – and no less than 35 (at the latest count) other LNG import proposals, some more speculative than others. In the unlikely event that all were built, it would represent some 30bn cf/d of import capacity, or roughly half the 60bn cf/d the US consumes.

The growth of LNG imports, although actively being promoted by no less a figure than Alan Greenspan, faces three major challenges – the permitting of import terminals, the pricing structure of the market and demand holding up in the face of high prices. Those opposed to new import terminals are mounting very considerable environmental objections. Apart from the usual 'Nimby' (not in my back yard) objections, considerable safety fears have been generated by the explosion and destruction of part of the Skikda LNG facility earlier this year. Although there is really no direct connection, environmentalists have used the accident to brand LNG as unsafe, a move that is complicating the permitting of new LNG import terminals.

However, new terminals are almost certain to be built, as the US is the key import market a large number of new LNG projects are targeting (see **Table 1**).

Success in promoting new LNG facilities largely depends on gaining longer-term financial commitments. Traditionally the US has priced and bought gas short term, but financing LNG requires longer-term financial commitments. Similarly, the economics of LNG imports depends on prices remaining above $3/mn Btu, though for some importers this will be a very profitable level. The last threat is demand destruction – chemical producers moving offshore and generators moving back to coal. As noted above this is already happening with the 4.9% US gas sales decline in 2003. While limited moves would be helpful in rebalancing the market, too much would undermine the economics of some LNG import projects. Additional gas supplies from the Mackenzie Delta pipeline can easily be accommodated as the volumes are relatively small, but the Alaskan pipeline is generally thought to require gas price levels that would make LNG imports extremely profitable.

In sharp contrast to the radical changes likely to be seen in the North American gas market the other market areas around the world are much more predictable and, apart from Europe, much less developed.

## Central and Latin America

Central and Latin America remains an underdeveloped gas market characterised by only limited infrastructure. Mexico's reluctance to open to foreign investment means its gas resources are underdeveloped and over recent years the country has actually been importing increasing volumes of gas from the US. In contrast, large-scale

| Project | Details | Country | Operator | LNG cap (mn t/y) | Source fields | Resvs (tn cf) | Buyers/term contracts |
|---|---|---|---|---|---|---|---|
| **Start-up 2003** | | | | | | | |
| Atlantic LNG | 3rd train | Trinidad | Atlantic LNG | 3.3 | Trinidad offshore | | US, Spain |
| MLNG Tiga | 3rd train | Malaysia | Petronas | 6.8 | Malaysia offshore | | Japan, Korea, Taiwan |
| **Start-up 2004** | | | | | | | |
| Damietta LNG | 1st train | Egypt | Segas | 5.2 | Red Sea fields | | Spain |
| NWS JV | 4th train | Australia | Woodside | 4.2 | North Rankin + 6 fields* 2nd p'line | | Japan, S Korea, China |
| Rasgas II | 3rd train | Qatar | ExxonMobil | 4.7 | North field | 900 | |
| **Start-up 2005** | | | | | | | |
| Idku – ELNG | 1st train | Egypt | Egyptian LNG | 3.6 | Simian Sienna (WDDM) | 13 | France |
| NLNG | 4th/5th train | Nigeria | Nigeria LNG | 7.5 | Onshore fields | | BG to Europe, US |
| Oryx GTL Ph 1 | GTL plant | Qatar | Sasol Chevron | 35,000 b/d | North field | 900 | |
| Qatargas | de-bottleneck | Qatar | Qatargas | 1.5 | North field | | UK and NW Europe |
| Rasgas II | 4th train | Qatar | Rasgas | 4.7 | North field | 900 | India, |
| **Start-up 2006** | | | | | | | |
| Atlantic LNG | 4th train | Trinidad | Atlantic LNG | 5.2 | Trinidad offshore | | US, Spain |
| Darwin | 1st train | Australia | ConocoPhillips | 3.3 | Bayu-Undan | 3.4* | Japan |
| Idku – ELNG | 2nd train | Egypt | Egyptian LNG | 3.6 | Sapphire (WDDM) field(s) | 13 | BG Mktng to US, Europe |
| NLNG | 6th train | Nigeria | Nigeria LNG | 5.4 | Onshore fields | | US, Europe |
| NWS JV | 5th train | Australia | Woodside | 5 | North Rankin + 6 fields* | | Far East, USWC |
| Oman LNG | 3rd train | Oman | Qalhat LNG | 3.8 | Onshore fields | | Europe, India |
| Oman LNG | de-bottleneck 1+2 | Oman | Qalhat LNG | 0.54 | Onshore fields | | Korea, various co's |
| Qatargas II | 1st train | Qatar | Qatargas | 7.8 | North field | 900 | UK |
| Snøhvit | 1st train | Norway | Statoil | 4.2 | Snøhvit, Albatross, Askela | 10.6 | US, Europe |
| **Start-up 2007** | | | | | | | |
| Angola LNG | 1st train | Angola | ChevronTexaco | 4 | Offshore fields | | US, Europe |
| Arzew | 1st train Ain El Bia | Algeria | Sonatrach | 4 | Gassi Touil + 3 others | 9 | US, Europe |
| Bioko | 1st train | Eq Guinea | Marathon | 3.4 | Alba field | | BG Gas Mktng, to US |
| Sakhalin 2 | 1st train, 2nd? | Russia | Shell | 4.8 | Piltun and Astokh | 28 | Japanese buyers |
| Tangguh | 1st/2nd train | Irian Jaya | BP, Pertamina | 6.8 | Weriagah | 14.4 | China, S Korea, Philippines |
| **Start-up 2008** | | | | | | | |
| Brass LNG | 2-train proposal | Nigeria | Agip (NAOC) | 10 | onshore oil and gas fields | US | |
| Brunei – Lumut II | 3rd train | Brunei | Shell | 4 | to be determined | | Japan, South Korea |
| Gorgon LNG | 1st & 2nd train | Australia | ChevronTexaco | 10 | Greater Gorgon (10 fields, | 40 | USWC, China |
| Mariscal Sucre | 1st train | Venezuela | Shell | 4.7 | Paria Penins fields, Plat | 10 | US, Mexico |
| Qatargas III | 5th train | Qatar | ConocoPhillips | 7.8 | North field | 900 | US |
| Rasgas III | 3rd train | Qatar | ExxonMobil | 7.8 | North field | 900 | US |
| **Start-up 2009** | | | | | | | |
| Darwin LNG | 1st train | Australia | Woodside | 7.5 | Sunrise, Troubador, Loxton | 7.7** | China, Korea, Taiwan |
| Oryx GTL PhII | 3-train facility | Qatar | Sasol Chevron | to 100,000 b/d | North field | 900 | |
| Qatargas II | 2nd train | Qatar | ExxonMobil | 7.8 | North field | 900 | US, Europe |
| Qatar GTL PhI | GTL plant | Qatar | Shell | 70,000 b/d | North field (800mn cf/d) | 900 | |
| **Start-up 2010** | | | | | | | |
| Rasgas III | 4th train | Qatar | ExxonMobil | 7.8 | North field | 900 | US |
| **Start-up 2011** | | | | | | | |
| Qatar GTL PhII | GTL plant | Qatar | Brunei LNG | 70,000 b/d | North field (800mn cf/d) | 900 | |
| Ras Laffan GTL | GTL plant | Qatar | ExxonMobil | 154,000 b/d | North field | | |
| **Possible projects** | | | | | | | |
| Jansz/Io field | Possible LNG | Australia | ExxonMobil | | Jansz/Io field | 20 | |
| Sulawesi LNG | 2-train proposal | Sulawesi | Pertamina | 6 | Donggi field | 4 | |
| Murmansk LNG | 3-train proposal | Russia | Gazprom | 16 | Shtokman (Barents Sea) | 55 | |
| Iran LNG | 2-train proposal | Iran | NIOC/BP | 9 | South Pars | 600 | China MoU from 2008 |
| Pars LNG | 2-train proposal | Iran | NIOC/Total | 8 | South Pars | 600 | India, |
| Persian LNG | 2-train proposal | Iran | NIOC/Shell/Reps | 9 | South Pars | 600 | |
| Bandar Tombak | 2-train proposal | Iran | NIOC/BG | 9 | South Pars | 600 | |
| Pars GTL | GTL plant | Iran | Sasol | | South Pars | 600 | |
| Iran GTL | GTL plant | Iran | PetroSA | | South Pars | 600 | |
| Pacific LNG | 2-train proposal | Bolivia | Repsol/YPF | 6 | Margarita field | 13 | Mexico, California |
| Peru LNG | 1-train proposal | Peru | Hunt Oil | 4.5 | Camisea fields | | Mexico, US |
| Qatar GTL | 6-train proposal | Qatar | Sasol Chevron | 130,000 b/d | North field | 900 | |
| Qatar GTL 2 | GTL plant | Qatar | Marathon | 120,000 b/d | North field | 900 | |
| Brazilan LNG | 1-train proposal | Brazil | Petrobras/ WM | 380,000 cm/d | BS-400, Santos Basin | 15 | |
| Ras Laffan GTL | GTL plant | Qatar | ConocoPhillips | | North field | 900 | |
| Nigeria floating | LNG proposal | Nigeria | Shell/Statoil | | Nnwa & Doro offshore fields | | US, Europe |
| MLNG IV | 4th train | Malaysia | MLNG IV | 6.8 | Offshore fields | | Japan, Korea, Taiwan |
| Atlantic LNG | 5th train | Trinidad | Atlantic LNG | 6+ | Offshore fields | | US, Spain |
| Yemen LNG | 2-train proposal | Yemen | Yemen LNG | 6.2 | Onshore fields | | India, Korea |
| Rasgas IV | 2-train proposal | Qatar | Rasgas | 15.6 | North field | 900 | US, Europe |

*Sources: LNG Industry by Fred Thackeray; published by CWC Group;* Petroleum Review *databases.*
** plus 400mn barrels condensate; **plus 300mn barrels condensate*

Table 1: Current global gas megaprojects

gas discoveries offshore Trinidad have allowed that country to develop a large-scale petrochemical industry based on gas and to progressively add additional LNG trains at the Atlantic LNG facility. As probably the lowest cost supplier of LNG into the US, the future for Trinidad looks bright. Train 3 started up last year and train 4 is set to start up in 2006. Venezuela has also been attracted by the potential to export gas as LNG, with the first train of the Mariscal Sucre LNG project due to start up in 2008. Gas development has now become a development priority for Venezuela with recent licensing of the offshore Platforma Delta confirming the potential and the commitment.

The progressive development of the pipeline network in the Southern Cone has been somewhat undermined by two recent developments. Supply shortfalls in Argentina have led to reductions in gas exports to Chile and other destinations (see *Petroleum Review*, June 2004) as well as restricting Argentina's economic recovery. The large offshore Brazilian gas find in block BS-400, with a reputed 14,8tn cf of reserves (see *Petroleum Review*, February 2004), has thrown into doubt the volumes and prices of the developing imports from Bolivia and also raised the possibility of a Brazilian LNG export facility. Similarly, there is now a Bolivian export project – Pacific LNG – to monetise gas from the Margarita field as LNG exports. After all the extended delays Peru's Camisea gas fields production is also the subject of an LNG export proposal, one that has already led to the fall of one government (see *Petroleum Review*, May 2004).

The various Latin American LNG proposals illustrate a key point about gas developments. At the present time it is really only the high income, relatively densely populated North America and Europe that can support comprehensive gas grids. In the rest of the world monetising gas involves either a pipeline to a major consumption area, usually a city or other large user such as a mining and ore processing region, or the development of an export LNG project.

| Rank | Country | 2007/2008 | end-2002 |
|---|---|---|---|
| 1 | Indonesia | 37.6 | 30.8 |
| 2 | Qatar | 33.0 | 14.3 |
| 3 | Algeria | 25.1 | 21.1 |
| 4 | Malaysia | 23.1 | 16.3 |
| 5 | Nigeria | 22.0 | 9.2 |
| 6 | Australia | 20.0 | 7.5 |
| 7 | Trinidad | 15.1 | 6.6 |
| 8 | Egypt | 12.4 | – |
| 9 | Brunei | 11.2 | 7.2 |
| 10 | Oman | 11.02 | 6.8 |
| 11 | Abu Dhabi | 5.6 | 5.6 |
| 12 | Russia (Sakhalin) | 4.8 | – |
| 13 | Venezuela | 4.7 | – |
| 14 | Norway | 4.2 | – |
| 15 | Angola | 4.0 | – |
| 16 | Equitorial Guinea | 3.4 | – |
| 17 | Alaska | 1.5 | 1.5 |
| 18 | Libya | 1.3 | 1.3 |
| | **Total** | **240.02** | **128.32** |

Table 2: LNG suppliers ranked by likely 2007/2008 capacity (mn t/y)

| Rank | Company | 2007/2008 | end-2002 |
|---|---|---|---|
| 1 | Shell | 25.1 | 10.35 |
| 2 | BP | 11.74 | 4.35 |
| 3 | ExxonMobil | 11.49 | 5.06 |
| 4 | BG | 8.09 | 1.93 |
| 5 | ChevronTexaco | 5.39 | 1.25 |
| 6 | ConocoPhillips | 3.15 | 1.05 |
| | **Total** | **64.96** | **23.99** |

Table 3: Capacity ranked by company (mn t/y)

## African LNG plans

In Africa we see a number of examples of this. In Egypt the gas fields of the Nile Delta and Western Desert supply Cairo and are now set to support two LNG facilities. In Libya most gas goes to the small LNG export facility at Marsa el Brega, but there are plans for a pipeline link to Italy. Algeria already has pipeline links to both Spain and Italy, with plans to expand their capacity. More than half of Algerian gas supplies are, however, exported as LNG via the facilities at Arzew and Skikda.

Over recent years the flaring of gas in the Nigerian oil fields has been greatly reduced as the result of the development of the LNG export facilities at Bonny, where the fourth and fifth trains are due onstream in 2005 and the sixth in 2006. There is also a two-train proposal for Brass LNG to export from the Brass river area from 2008. Two other West African producers are set to export LNG – Angola and Equatorial Guinea. For the moment both countries have single train proposals due for start-up in 2007. The only other significant gas projects are the Kudu and Temane gas fields in Mozambique, which are now going ahead, linked to power generation projects, and the gas fields like Sable, Oribi and Soekor that have been developed offshore South Africa.

## Middle East gas plans

The Middle East region is believed to contain over 40% of the world's remaining gas reserves. Iran, Kuwait and Saudi Arabia currently utilise all their production, while Abu Dhabi exports limited volumes as LNG. In contrast, both Qatar and Oman are significant LNG exporters. Although a high proportion of regional gas reserves are associated gas in the oil fields, the region contains the world's largest single dry gas field in the North Dome. The field contains a truly staggering 1,500tn cf straddling the Qatar/Iran median line. The current estimates are that 900tn cf are in Qatar's North field, with the remaining 600tn cf in Iran's South Pars field. As these two fields are one and the same, gas can migrate, which has led to something of a development race between the two countries to develop the resource. Qatar was undoubtedly quicker off the mark, with both the Qatargas and Rasgas LNG projects already in operation. As **Table 1** shows, progressive expansion of both are planned over the next few years, while from 2009 onwards a number of gas-to-liquids (GTL) projects start to come onstream (see also *Petroleum Review*, July 2004).

In contrast, while there are a number of both LNG and GTL facilities planned for Iran's South Pars field these are generally rather earlier in the planning process and have been listed as 'possible projects'. Phase 1 of the South Pars gas and condensate project came onstream in May 2004 and condensate production should build up to 40,000 b/d. The next phases to come onstream are 4 & 5, that were due to start up as *Petroleum Review* went to press, with a capacity of 80,000 b/d of condensate and 35,000 b/d of LPG. South Pars gas will also be used to augment pipeline supplies, which are already developed and link most of the main cities and are also exported. There are plans to inject South Pars gas into a number of depleted oil fields to repressurise them and expand production. Gas is also to be pipelined from Qatar to Abu Dhabi in the Dolphin project, even though Abu Dhabi is an LNG exporter. Saudi Arabia is relatively short of incremental gas supplies, having long established the Master Gas System which collects all the associated gas from the producing fields for use in power stations, desalination plants and as the basis of the extensive petrochemicals operations of Sabic. This relative shortage is the main reason behind the recent attempts to bring in international companies to look for gas, resulting in recent acreage awards to Lukoil, Repsol/YPF and CNPC. Kuwait's limited gas supplies are also fully utilised.

## Far East

The particular geography of the Far East appears to have militated against the development of a major gas pipeline infrastructure while encouraging the development of LNG supply. This, however, is starting to change with the promotion of a number of regional pipeline links (see *Petroleum Review*, September 2004). The early history of LNG was all about developing Indonesian and Malaysian supplies to meet demand in the three islands – Japan, South Korea and Taiwan (South Korea, while not a geographic island, has been rendered an effective island by North Korea).

**Table 1** clearly shows that the major regional suppliers will continue to expand, with Indonesia adding a third facility at Tangguh, starting up in 2007, and possibly one in Sulawesi. The newest of the regional suppliers – Australia – is set to expand fast with the North West Shelf joint venture commissioning a fourth train this year and a fifth train in 2006. It is to be joined by Darwin's first train in 2006, utilising Bayu Undan gas. In 2008 a further two-train LNG facility is to be commissioned to commercialise the Gorgon area gas fields. By late in the decade Australia appears set to become one of the major LNG suppliers. Just as Australia has become the major new supplier, China and India have become the major new markets that will absorb a significant proportion of new supplies.

If all the planned projects come to fruition by the end of the decade a very high proportion of the currently known gas discoveries will be in production or lined up for production.

As shown in **Table 2** by 2007/2008 the 18 producers of LNG will have a combined capacity of just over 240mn t/y compared with the 128mn t/y that the existing 12 LNG producers had at end 2002. By 2007/2008 the big six – Indonesia, Qatar, Algeria, Malaysia, Nigeria and Australia – will each have over 20mn t/y of capacity. In terms of the involvement by the majors and supermajors, **Table 3** clearly shows that Shell has by far the largest commitment to LNG with a 2007/08 capacity more than double that of BP and ExxonMobil. **[Tables 2** and **3** are based on information drawn from *LNG Industry* by Fred Thackeray and published by CWC Publishing in 2003.]

*Note: Space considerations mean that this article has concentrated on the monetising of remote gas supplies via LNG and GTL. The development of Russian gas supplies and potential pipeline export supplies to Europe and China along with the development of Central Asia supplies will be covered in a later issue.*

## Key gas data

- Ultimate gas reserves: 12,000tn cf (of which conventional gas 10,000tn cf = 10 Pcf)
- Discovered gas reserves to date: 9,000tn cf
- Cumulative gas production to 2002: 2,700tn cf (non-reported losses mean that this figure could be closer to 3 Pcf than 2.7 Pcf)
- Remaining (2003) discovered gas reserves: 6,204.9tn cf*
- Discovery in 2002 (according to IHS Energy press release): 30.4tn cf in world outside US, with 7.2tn cf discovered in Opec countries
- Total gas discovery 2002: 35tn cf; 2001: 65tn cf; 2000: 129tn cf; 1999: 121tn cf; 1998: 77tn cf
- Peak production: 140tn cf in 2030 (according to Laherrere); 180tn cf (EIA/IEA)
- Global production (excl. flared or recycled/reinjected) in 2003: 92.4tn cf*

According to Cedigaz, out of the 111tn cf gross produced in 2002, 11% is reinjected, 3% is lost and 5% flared or vented, leaving 81% as marketed gas (89.9tn cf).

**Annual gas trade: 25tn cf**

**Of which, pipeline gas: 20tn cf; as LNG: 5tn cf**

So 67tn cf of gas is consumed in country of production. [NB what is extracted is gross minus reinjected, which is about 100tn cf, meaning that 75tn cf of gas is utilised in producing countries.]

*BP Statistical Review *June 2004*

| Region | Discovered reserves | Ultimate reserves | Cumulative production | Remaining known reserves |
|---|---|---|---|---|
| Mid East | 2,860 | 3,000 | 200 | 2,660 |
| CIS | 1,830 | 2,000 | 700 | 1,100 |
| US | 1,200 | 1,250 | 960 | 240 |
| Canada | 400 | 420 | 160 | 260 |
| Asia | 920 | 1,150 | 180 | 740 |
| Africa | 620 | 800 | 100 | 520 |
| L America | 580 | 800 | 150 | 430 |
| Europe | 620 | 800 | 300 | 320 |
| Canada | 215 | 250 | 155 | 60 |
| World | 8,800 | 10,000 | 2,700 | 6,100 |
| US/Canada | 1,600 | 1,670 | 1,120 | 500 |
| Opec | 3,500 | 3,600 | 400 | 3,100 |

*Data sources: recent gas presentations by Jean Laherrere, see*
www.peakoil.net/JL/JeanL.html
www.iiasa.ac.at/Research/ECS/IEW2004/index.html

Reserves and production by region 2002–2003 (in tn cf) energy INSTITUTE

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# Looking to the less conventional

**As Canada's conventional oil and natural gas production goes into decline, the country's oil and gas sector must search out unconventional ways of meeting demand. Thank goodness for high energy prices, writes *Gordon Cope*.**

It's been busy lately in the Canadian oil patch. According to the Canadian Association of Petroleum Producers (CAPP), a record total of 12,951 gas and 4,845 oil wells were drilled in 2003, an increase of 33% over the year before. And 2004 is expected to be just as lively, with FirstEnergy Capital of Calgary predicting that the industry will complete 16,000 gas wells and 4,500 oil wells as it endeavours to replace sagging conventional production.

Much of this activity has, of course, been fuelled by astronomical energy prices, which averaged $31.04/b for WTI and $5.40/mn Btu at Henry Hub through 2003. According to the Conference Board of Canada, oil and gas sector revenues jumped last year to C$106bn, up from C$86bn in 2002.

The coffers are expected to be even fatter this year. So far, gas prices averaged $5.76/mn Btu and the oil price $36.36/b for 1H2004. Revenues are expected to set another record, growing 8%, to C$116bn.

But a healthy energy price is only one (albeit large) factor that has contributed to the frenetic pace. The Canadian oil patch is undergoing an evolution on several fronts that will affect the industry for the next two decades, and the sector is scrambling during the good times to effect the necessary changes.

## Less conventional

According to CAPP figures, conventional oil production (which includes light, medium and heavy crude) increased slightly from 1,449,000 b/d in 2002 to 1,462,000 b/d in 2003. However, the numbers, which are buoyed by increased production off the East Coast, conceal a 5% decline in production of light and medium crude in Western Canada, from 603,000 b/d to 572,000 b/d. Furthermore, in spite of a recent announcement by the Alberta Government to earmark C$200mn in royalty reductions towards enhancing oil recovery, production is expected to take a further dive of roughly 5%, to 543,000 b/d, in 2004.

The decrease in conventional production is accelerating the turnover of ownership as the supermajors, taking advantage of high reserve prices, have been divesting ageing fields (see p14). ChevronTexaco, for instance, parted company in May with properties it has held for almost half a century, selling 38,500 boe/d of conventional production in Western Canada for just a little under C$1.1bn. The buyers of such properties have largely been junior oil companies and Royalty Income Trusts (which purchase producing fields and pay out most of the cashflow to unit holders before taxes).

## More unconventional

Much of the funds raised by the supermajors through sales of conventional fields are being reinvested (at the rate of approximately C$6bn annually) in oilsands. The National Energy Board (NEB) forecasts oilsands output will hit the 1mn b/d mark by the end of 2004 as incremental improvements at the Syncrude, Suncor and Athabasca projects add another 150,000 b/d to the previous year's average.

In addition, several major projects have been approved this year. Suncor received the go-ahead to expand its oilsands operation with a C$1.5bn refinery upgrader that will boost synthetic crude production from 225,000 b/d to 330,000 b/d. Meanwhile, Nexen was given the green light to proceed with its C$3.3bn Long Lake project, and Canadian Natural Resources received formal approval to build Horizon oilsands, an C$8.5bn project that will start producing 232,000 b/d of synthetic crude by 2008. The NEB predicts that production may more than double in the next decade, to 2.2mn b/d by 2015, if all goes well.

Cost overruns remain a big *if*, however. When Syncrude's Stage 3 expansion was announced in 2001, enhancements to its upgrader and a new train at the open pit mine were expected to cost C$4.1bn. By the time it comes onstream in 2006, a year late, the project may exceed C$7.8bn. Suncor and Athabasca have seen similar cost escalations. Companies are thus having a hard look at their projects while the industry roots out the causes for the overruns. Various solutions, including stepping major projects to avoid competition for labour, construction databases based upon cold climate experience, and relieving transportation bottlenecks in northern Alberta, are being touted.

But one important factor floats tantalisingly beyond their control – the cost of natural gas. Oilsands projects more closely resemble manufacturing plants than conventional exploration plays. The risk of finding the oil is nil – the viability of a project rests upon the ability to control production costs. The price of producing a barrel of synthetic crude has risen to the C$18/b range, largely due to surging natural gas prices. Even with advances in technology to reduce energy input, the NEB estimates that it still takes approximately 250 cf of gas to mine the bitumen – in-situ production through steam injection requires 1,000 cf of gas, and upgrading to synthetic oil requires 300cf to 700 cf of gas (depending on how much gas is converted to hydrogen for processing). If production reaches 2.2mn b/d, the oilsands will consume as much as 2.5bn cf/d of gas, or 16% of Canada's estimated production, placing intolerable demands on supplies.

Oilsands companies are concerned, but not panicky. Pundits say strong natural gas prices will provide incentives for further efficiency improvements (such as low-pressure SAGD), new recovery technologies (such as solvent-based recovery processes), and substitution (including the gasification of bitumen residues to produce hydrogen). 'Gas won't get sufficiently expensive to force companies to abandon plans on that one factor, but it will put pressure to reduce energy consumption,' says Bob Dunbar, a Research Director at CERI, a Calgary-based consultancy. 'They are doing a lot of research in this area.'

## Same old gas

Statistics Canada reported that, in 2003, gas production fell 3.8%, to approximately 17bn cf/d. In addition, Canada's consumption also rose 2.2% last year, to about 7.1bn cf/d. The two factors were instrumental in cutting US exports by 5.6%, to 9.8bn cf/d. And the long-term prospects aren't encouraging. CERI projects gas production in the Western Canada Sedimentary Basin to drop from its current level of above 16bn cf/d to around 5bn cf/d by 2025 as conventional fields deplete.

All is not lost, however. EnCana, for instance, plans to increase its current production rate of 3.1bn cf/d by 10% annually by tapping into unconventional gas plays. It recently paid C$369mn to purchase mineral rights to Cutbank Ridge, a tight gas play (high porosity, low permeability sands) in northeast British Columbia that holds around 4tn cf of recoverable reserves. While individual wells cost C$4mn to drill and complete, production lasts a long time, and the play has the potential to add several hundred million cf/d to production.

In addition, coalbed methane (CBM) has huge potential in western Canada. According to a recent study by the Alberta Geological Survey, Alberta's coalbed resource could contain approximately 500tn cf. While tests have shown average production to be relatively low (it would take approximately 10,000 wells to produce 1bn cf/d), decline rates are significantly lower than conventional fields.

The major drawbacks with CBM are environmental and social. The US has been producing CBM for several decades, and the practice has been criticised for degrading land and water supplies in Wyoming and Colorado. In addition, wells must be spaced much more closely together than in conventional fields, unduly monopolising farmer and recreational user's surface rights. In April, protesters forced the indefinite postponement of mineral rights auctions in the idyllic Crowsnest Pass area of southeast British Columbia.

Most hope in rejuvenating natural gas production lies to the north. For several decades, 6tn cf of proven reserves have been stranded in the Beaufort Sea region. The Mackenzie gas project seeks to connect the reserves to the existing North American natural gas network through a 1,300-km pipeline running south to Alberta. The project is jointly owned by Imperial Oil, Inuvik's Aboriginal Pipeline Group, ConocoPhillips, Shell Canada and ExxonMobil. Originally planned as a 1.2bn cf/d line, it is to be expanded to 1.9bn cf/d, and a second gas liquids line added. Currently, the project is in the engineering stage, but the owners hope to enter the regulatory approval stage this summer when they file a series of applications with the federal government. If all goes well, they envision a go-ahead by 2006, followed by three years of construction and a start-up in late 2009.


Photo courtesy of Petro-Canada

**Drilling activity in the Wildcat Hills/Benjamin Creek area**

## Refineries on the up

Refineries in Canada, which have suffered through several years of mediocre returns, are finally seeing healthy profits. Refineries make their money on the margin, or difference between what it costs to buy crude and the price refined petrol fetches in the wholesale market. A typical margin is in the order of 12–13 Canadian cents per litre. During 2Q2004, however, margins have been closer to 20 cents. 'Margins in the US and Canada are at record high levels,' says Michael Ervin, President of MJ Ervin & Associates, a Calgary-based consultancy. 'It is absolutely a great time to be making a litre of gas.'

Paradoxically, this boon is due to a combination of environmental regulations (which make it more difficult and expensive to build new refineries), the cost of meeting emission controls, and healthy economic growth. Canada has 20 refineries with a capacity of 1.9mn b/d, but no new refineries have been built for several decades. Over the last 12 years, demand for petroleum products has grown at around 2% per year. While there is some potential for expansion, refineries are instead dedicating their capital budgets to meeting the most recent regulatory fiat – low-sulphur diesel, the deadline for which has been set at June 2006. Shell, for instance, is spending $400mn to upgrade its Edmonton and Montreal area refineries. However, offshore refiners are reluctant to spend such sums to meet specific North American needs. As a result, Canada must import around 10%–15% of its petrol needs during the busy summer months, largely from the US, where the shortage is equally grave.

Unfortunately, the good times won't last. 'The high margin plants the seeds of its own demise,' says Ervin. 'It has encouraged refiners to configure to maximise gas[oline] output. Inventories will start to build.'

In the longer term, however, the lack of capital for expansion and the difficulty of building new facilities will mean that Canada's burgeoning oil-sands production will have to be shipped abroad for refining. That will necessitate the need for new and expanded pipeline systems.

## Pipelines heading south

Enbridge, Canada's largest pipeline system, wants to spend $550mn to expand its Lakehead system southwards in the US. A new, 1,000-km pipeline will carry up to 225,000 b/d of crude oil from Superior, Wisconsin, south to the Wood River hub in southern Illinois. It will complement the company's recent purchases of pipeline systems used to move crude from

*...continued on p29*

# How realistic are Opec's proven oil reserves?

**Questions have increasingly been raised about the actual size of Opec's proven reserves, which stood at 819bn barrels at the start of 2003 despite a lack of significant discoveries between 1980 and 2002 and a production of 186bn barrels during the same period. Many experts are also questioning how the oil cartel's reserves suddenly jumped from 467.39bn barrels in 1982 to 760.48bn in 1988, an increase of 293.11bn barrels at a time when not much exploration or drilling was conducted. Furthermore, some oil industry insiders estimate Opec's current spare capacity at no more than 0.92mn b/d, rather than the 'official' figure of 3mn b/d. Here, *Dr Mamdouh G Salameh** suggests that Opec's proven reserves have been overstated by 300bn barrels.****

In the late 1980s there were huge and abrupt increases in the announced proven reserves for several Opec countries. Between 1982 and 1988 proven reserves jumped suddenly from 467.39bn barrels to 760.50bn barrels.[1] These sudden reserves additions coincided with Opec's decision – informally in 1982 and then formally in 1983 – to adopt a production quota system in defence of the oil price, which was coming under heavy pressure. Members suddenly added huge amounts of reserves in order to secure for themselves a bigger production share. Opec's idle production capacity was rising, leading to fears that a production free-for-all would precipitate a downward price spiral. Indeed, the oil cartel's fears began to materialise over the period 1985–1986. The producers, following a natural tendency to increase production in order to offset the damaging effect of weakening prices on revenues, brought about a collapse of price.[2]

| Country | Proven reserves (1982) | Net reserve additions (1982–1988) | Proven reserves (1988) |
|---|---|---|---|
| Algeria | 9.44 | –0.24 | 9.20 |
| Indonesia | 10.53 | –1.53 | 9.00 |
| Iran | 56.15 | 36.71 | 92.86 |
| Iraq | 59.00 | 41.00 | 100.00 |
| Kuwait | 67.15 | 27.38 | 94.53 |
| Libya | 22.19 | 0.61 | 22.80 |
| Nigeria | 16.75 | –0.75 | 16.00 |
| Qatar | 3.45 | 1.05 | 4.50 |
| Saudi Arabia | 165.48 | 89.51 | 254.99 |
| UAE | 32.35 | 65.76 | 98.11 |
| Venezuela | 24.90 | 33.61 | 58.51 |
| **Total Opec** | **467.39** | **293.11** | **760.50** |

*Source:* Opec Annual Statistical Bulletins, *1982–2003*

Table 1: Opec's net reserve additions, 1982–1988 (bn barrels)

Earlier, each Opec nation was assigned a share of production based on its own annual production capacity. However, the organisation changed the rule in the early 1980s to also consider the oil reserves of every member country. As a result, most Opec member countries promptly increased their reserve estimates. Between 1982 and 1988, Venezuela raised its proven reserves by 33.61bn barrels to 58.51bn. Then Iran announced an addition to its reserves amounting to 36.71bn barrels and the UAE added 65.76bn. Iraq joined the fray next, by adding a total of 41bn barrels, to be followed in 1988 by Saudi Arabia adding 89.51bn. All in all, Opec added 293.11bn barrels of reserves during the period 1982–1988 (see **Table 1**).

*[The latest edition of the* BP Statistical Review, June 2004, *claims to have gone back to the original sources for the large reserve revisions now incorporated. As a result Opec reserves at end 2002 rise from the 819bn barrels reported in BP's June 2003 edition to 881.6bn barrels as reported in the 2004 edition. The end-2003 figure quoted in the 2004* Review *is 882bn barrels. The principal revisions within the Opec official reserves are: Iran rises from 89.7bn barrels to 130.7bn barrels; Algeria from 9.2bn barrels to 11.3bn barrels; Libya from 29.5bn barrels to 36bn barrels; and Nigeria rises from 24bn barrels to 34.3bn barrels. All other Opec reserve estimates were essentially unchanged. To give some idea of the magnitude of the reserve changes in the four countries, they are equivalent to the entire initial North Sea reserves, or the equivalent of two and a half years of global production. There will be a range of opinions as to the plausibility of these revisions. Ed.]*

Several explanations have been suggested for the sudden jump in Opec reserves between 1982 and 1988, none too satisfactory. One explanation is that these reserve additions were clearly not the result of new discoveries made during the years in question and are regarded by many as 'political reserves', ie reserves that were 'proven' either to support each country's demands for

| Country | Opec reserves (1988) | Reserve additions 1982–1988 | Production 1989–2002 | Drawdown 60% | Additions 40% | Actual reserves 2002 |
|---|---|---|---|---|---|---|
| Algeria | 9.20 | –0.24 | 4.15 | 2.49 | 1.66 | 10.86 |
| Indonesia | 9.00 | –1.53 | 6.68 | 4.00 | 2.67 | 11.67 |
| Iran | 92.86 | 36.71 | 18.86 | 11.32 | 7.54 | 63.69 |
| Iraq | 100.00 | 41.00 | 7.92 | 4.75 | 3.17 | 62.17 |
| Kuwait | 94.53 | 27.38 | 10.00 | 6.00 | 4.00 | 71.15 |
| Libya | 22.80 | 0.61 | 8.43 | 5.06 | 4.25 | 25.56 |
| Nigeria | 16.00 | –0.75 | 10.63 | 6.38 | 3.92 | 20.25 |
| Qatar | 4.50 | 1.05 | 2.83 | 1.70 | 1.13 | 4.58 |
| Saudi Arabia | 254.99 | 89.51 | 40.92 | 24.55 | 16.37 | 181.85 |
| UAE | 98.11 | 65.76 | 12.50 | 7.50 | 5.00 | 37.36 |
| Venezuela | 58.51 | 33.61 | 14.50 | 8.70 | 5. 80 | 30.70 |
| **Total** | **760.50** | **293.11** | **137.42** | **82.45** | **54.97** | **519.84** |

*Sources:* Opec Annual Statistical Bulletins, *1982–2003;* BP Statistical Review of World Energy, *June 2003*

Table 2: A revision of Opec's current reserves (bn barrels)

higher output allocation within the Opec quota system, or as a result of excessive upward revisions of earlier estimates.[3]

Another explanation may be that the assessment of Opec reserves was originally based on a recovery rate of 20% of oil-in-place and was later re-evaluated at a recovery rate of 50% – far above the current global rate of 29% and, therefore, unjustifiable.

However, the abrupt increase in announced Opec reserves in the late 1980s was probably a mixture of upward revision of old underestimates and some wishful thinking.

In countries of the Gulf, there has been a lack of consistency and transparency regarding reserves. The statistics reported could change due to revised estimates of oil-in-place or changes in the recovery factor. Together with some other technicalities, there are also grounds for arguing that some reserves are overstated.[4]

## Reserves reduction

Prior to the introduction of the Opec quota system, net additions to Opec reserves during the period 1978–1982 amounted to only 19.5bn b.[5] However, they suddenly jumped by 293.11bn barrels between 1982 and 1988 – although there was no evidence of major discoveries or extensive exploration or drilling during that period.

A more reasonable estimate of current Opec reserves should be 519bn barrels *not* 819bn – a reduction of 300bn barrels. This is based on an average global recovery rate of 29%, rather than on a rate of 50%, and also on my calculations of Opec's own production, consumption and discovery figures. The reserve estimate of 519bn barrels may also be arrived at by using a calculation process devised by Prof. Kenneth S Deffeyes of Princeton University (see **Table 2**). This entails subtracting out any abrupt jump during 1982–1988 from each Opec country's reserves. After the 1980s, Prof. Deffeyes estimated that 60% of the production was a drawdown from the reserves and 40% was either corrections for previous underestimates or the addition of new oil reservoirs. The 60:40 split is intended as an average performance figure for those Opec countries that reported abrupt reserve increases.[6]

Consequently, some 300bn barrels must be deducted from Opec's current proven reserves of 819bn barrels to give a realistic figure of 519bn barrels. In so doing, global proven reserves of some 1tn barrels of oil must also be reduced by an equivalent quantity. This will, in turn, reduce the ultimate global reserves from the consensus figure of 2,100bn barrels to 1,800bn, with adverse impact on global oil supplies and the price of oil.

## Peak production

The current global reserves/production (R/P) ratio is 37 years based on global proven reserves of 1047.7bn barrels (at the beginning of 2003) and an annual production of 28bn barrels. A downward revision of Opec reserves by 300bn barrels will reduce the R/P ratio by 10 years to 27. *[On the basis of BP's latest reserve revisions there are now 1147.7bn barrels of global reserves giving an R/P ratio of 41. However given rising demand and oil's depletion pattern R/P ratios are largely meaningless. Ed.]*

However, whether the figure is 37 years or 27 years, one has to realise that oil production will not stay flat during that period and then suddenly drop to zero. Rather, it will rise to a peak after which mankind is faced with an era of declining production. Thus it is clear that 'peak production' will be an important turning point in our future

| Year | Added in year | Annual production | As % of annual production |
|---|---|---|---|
| 1992 | 7.80 | 23.98 | 33 |
| 1993 | 4.00 | 24.09 | 17 |
| 1994 | 6.95 | 24.42 | 28 |
| 1995 | 5.62 | 24.77 | 23 |
| 1996 | 5.42 | 25.42 | 21 |
| 1997 | 5.92 | 26.22 | 23 |
| 1998 | 7.60 | 26.75 | 28 |
| 1999 | 13.00 | 26.22 | 50 |
| 2000 | 12.60 | 27.19 | 46 |
| 2001 | 8.90 | 27.81 | 32 |
| 2002 | 9.00 | 26.99 | 31 |
| 2003 | 2.27 | 28.11 | 8 |
| 1992–2003 | 89.08 | 311.97 | 29 |
| **Average** | **7.42** | **26.00** | **29** |

*excluding the US and Canada

*Sources: IHS Group's 2003* World Petroleum Trends Report (WPT); BP Statistical Review of World Energy, *1993–2003*

Table 3: Global crude oil reserve additions*, 1992–2003 (bn barrels)

| Country | Current capacity | Current production | Capacity utilisation | Spare capacity |
|---|---|---|---|---|
| Algeria | 1.66 | 1.66 | 100% | – |
| Indonesia | 1.20 | 1.18 | 98% | 0.02 |
| Iran | 3.50 | 3.45 | 99% | 0.05 |
| Iraq | 2.00 | 1.40 | 70% | 0.60 |
| Kuwait | 2.15 | 2.15 | 100% | – |
| Libya | 1.45 | 1.45 | 100% | – |
| Nigeria | 2.18 | 2.18 | 100% | – |
| Qatar | 0.90 | 0.90 | 100% | – |
| Saudi Arabia | 9.25 | 9.00 | 97% | 0.25 |
| UAE | 2.50 | 2.50 | 100% | – |
| Venezuela | 3.00 | 3.00 | 100% | – |
| **Total** | **29.79** | **28.87** | **97%** | **0.92** |

*Sources: Energy Intelligence Group (EIG); International Energy Agency (IEA)*

Table 4: Opec's current sustainable capacity and capacity utilisation (in mn b/d)

reliance on oil and, therefore, consumers and governments alike should be made aware how close such a date might be.

The world is currently consuming 28bn barrels of oil a year on a rising trend, yet on average finding only 7.42bn barrels a year.[7] Over the period 1992–2003, only 29% of the global oil production has been replaced by new discoveries. The cumulative shortfall over the period 1993–2002 amounted to 222bn barrels (see **Table 3**).

According to the IHS Energy Group's 2003 *World Petroleum Trends Report (WPT)*, 2003 was probably the first year to have recorded no large discoveries at all, with only 2.27bn barrels of new reserves added. We would have to go back to the early 1920s to find a year when fewer large oil discoveries were made.[8]

## Impact on ultimate global reserves

Global oil production will probably reach a peak sometime during this decade. After the peak, the world's production of crude oil will fall, never to rise again. The world will not run out of oil, but developing alternative oil sources on a large scale will take at least two decades, if not more. The slowdown in oil production may already have started; the current price fluctuations for crude oil and natural gas may be the preamble to what may be the 'final energy crisis'.[9]

A growing body of opinion among energy experts suggests that global conventional oil production will peak sometime during this decade, probably between 2004 and 2009. Declining production will cause a global oil shortage. However, my own research indicates that the peak in global oil production may even occur much earlier, probably between 2004 and 2005. That, however, will depend on two factors:

- the reality of Opec proven reserves, and
- Opec sustainable production capacity.

## Opec oil production capacity

At present, Opec is thought to have a spare production capacity of 3mn b/d. However, oil industry insiders maintain that Opec's spare capacity is far less than that – the latest estimate for current capacity being 29.79mn b/d. 'Capacity' here is defined as 'being attainable within 30 days and sustainable for three months'. With a current production of 28.87mn b/d, Opec's readily available spare capacity is now estimated at only 0.92m b/d (see **Table 4**). The spare capacity would have been even smaller if not for the frequent disruption of Iraq's oil production and exports due to the sabotaging of the country's production and export facilities. At present, there is no non-Opec spare capacity as new reserves have been brought rapidly into production.

However, three leading Opec producers have capacity problems. Venezuela's production capacity shrank from 3.5mn b/d in 1997 to 3mn b/d in 2003 because of a lack of investment funds and also annual output declines ranging from 15%–25%. The country has an ambitious five-year plan to raise capacity to 5.5mn b/d by 2008. This involves the expenditure of up to $43bn on oil exploration, with western oil companies providing some $23bn and Venezuela contributing the balance. Venezuela, however, does not have the funds to contribute $20bn and, given current political circumstances in the country, the foreign investors would not be that keen to stump up a further $23bn. Venezuela's plan to expand capacity is, therefore, unrealistic. At best, it may be able to raise capacity to 4mn b/d by 2010.[10]

Iran also appears to be having difficulty maintaining production levels, which are subject to large month-to-month swings. Iran's current sustainable production capacity is estimated at no more than 3.5mn b/d. Some independent experts maintain that the country is facing technical problems at its major onshore oil fields, to an extent that Iran's production capacity is falling below its Opec production quota. Production declines from these ageing oil fields currently amount to 250,000 b/d a year. The opening up of Iran's oil sector to foreign investment is partly spurred by plans to increase oil production capacity to 6mn b/d by 2010 from current levels of 3.5mn b/d. Many analysts, however, believe that this target is not achievable.

Even the mighty Saudi Arabia is having problems maintaining its capacity. The country's readily available spare capacity is estimated at no more than 250,000 b/d, and not the 3mn b/d previously assumed. Any new addition to capacity will go to offset the production decline in its giant Ghawar oil field, which accounts for 59% of Saudi production. There are persistent reports that the country is facing serious water incursion problems in the Ghawar oil field. Ghawar, the world's largest oil field, needs 7mn b/d of seawater injected to prop up the reservoir pressure.[11]

Almost 90% of Saudi oil production comes from just eight ageing oil fields. Saudi Arabia is now drilling only horizontal wells in an effort to maintain production flows, with around 200 additional horizontal wells drilled each year.[12] To many this sounds like a country that was working hard just to maintain production rather than one capable of increasing production by simply opening the tap when more production is needed.

Some experts believe that the Saudi 'miracle' of almost effortless, cheap production is nearing its end. These experts think that the Ghawar oil field, with a production of 5mn b/d, could be running down. They also suspect that most of the other big Saudi fields, including Abqaig and Berri, could be past their peak. They speculate that the Saudis may soon have to develop fields once deemed marginal, just to maintain capacity.

## Impact on global oil price

There is no more truly 'global' market than oil – a fluid commodity easily shipped between producers and consumers spread all over the planet. Every little jump in supply or demand can send ripples around the world and cause spikes in the oil price.

A downward revision of Opec reserves and sustainable production capacity are bound to impact on global oil prices. Opec is supposed to be the 'global swing producer' of last resort, with so much spare capacity that it can flood the oil market any time. The revelation that its proven reserves are overstated by 300bn barrels could have a huge psychological impact on the global oil market and could trigger a sharp rise in the oil prices.

Deducting 300bn barrels from Opec reserves is equivalent to taking a major oil producer like Saudi Arabia out of the global oil markets. Coupled with far less spare capacity than was previously assumed, this could add $10–$15/b to the price of oil by 2010, with oil prices ranging from $40–$45/b according to my calculations. Such a development could also undermine global oil security and lead to panic buying reminiscent of the 'Spot Market' in 1979–1980, where major oil users bid against one another for the dwindling oil supply.

If there is a continuing use for oil, what can we do to extend the supply? More oil can be squeezed out of existing fields, oil can be produced from tar sands and oil shale – but will it be enough to offset a real shortage?

## What is the alternative?

While technological advances such as horizontal drilling and seismic imaging could help reduce drilling costs, it will not find oil that does not exist. And while some unconventional oil such as extra heavy oil, tar sand oil and GTL (gas-to-liquids) oil will eventually be available, it is reckless to believe, on the basis of evidence available at present, that there will be enough to replace shortfalls in conventional oil.

In 2003, unconventional oil contributed 1% to the global conventional crude oil consumption. However, unconventional oil will be hard pressed to meet 2% of the global demand for oil in 2005, or about 3% and 4% in 2010 and 2020 respectively. As for renewable energy sources, they contributed a mere 1% to the global primary energy demand in 2003. Their contribution may not exceed 7% in 2025, possibly rising to 13% by 2050. In other words, the combined contribution of unconventional oil and renewable energy sources will make only a modest dent in the future need for energy.[13]

This much is certain – no initiative put in place starting today can have a substantial effect on the peak production year. No Caspian Sea exploration, no drilling in the South China Sea, no renewable energy project, no unconventional oil can be brought on at a sufficient rate to avoid a bidding war for the remaining oil.

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## Footnotes

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*...continued from p25*

Oklahoma to Chicago. By reversing the flow along these systems, Enbridge hopes to eventually be able to ship Canadian crude as far as the Gulf Coast, where it would compete with local and offshore supplies of heavy oil.

Similarly, Terasen, a pipeline company based in Vancouver, hopes to expand its system in British Columbia. It currently owns the TransMountain pipeline that moves 200,000 b/d of crude west from Alberta to the Pacific coast. It has plans to increase the flow to as much as 800,000 b/d. The extra supply could then be moved, by tanker, south to California or east to Asian markets.

## Full coffers

With the continued strength of energy prices, Canadian companies are currently facing an embarrassment of riches. Coffers are full, yet there are only so many energy projects available domestically to absorb the cash.

Increasingly, the major players are looking abroad. In May, Petro-Canada paid C$1.15bn to buy a stake in the Buzzard field in the North Sea, about 100 km northeast of Aberdeen. The acquisition gives it a 29.9% interest in the joint venture, which is led by Calgary's EnCana. Oil production from the field is expected to start in late 2006 and peak at around 180,000 b/d. Similarly, Talisman will spend a record C$2.3bn on capital investments and exploration this year in an effort to boost production to 450,000 b/d. Half will be spent in North America, one-quarter in the North Sea, and the rest on projects in Malaysia, Vietnam, Algeria and Colombia.

## The future

All good things eventually come to an end, however. Is the Canadian oilpatch concerned that the cycle of high prices has peaked? 'The industry as a whole has been fairly robust, and we expect it to continue to be so,' says Onno DeVries, General Manager of oilsands and markets for CAPP.

'Generally, the energy sector has been in a bullish upturn in the 2000s,' agrees Martin King, an analyst at FirstEnergy Capital. 'They're looking at better returns and better prices in the next five to six years.'

But Louis Thériault, Head Statistician at the Conference Board of Canada, sounds a more cautious note. 'I have met with ten senior vice presidents of major oil companies recently and they are very nervous. They don't take anything for granted. Prices don't have to go down much to make current drilling levels relatively expensive.'

# Developing gas in iceberg alley

**The Newfoundland offshore petroleum industry produces around one-third of Canada's conventional light crude. It currently pumps over 300,000 b/d of oil from the Hibernia and Terra Nova fields on the Grand Banks, with production set to rise sharply when White Rose comes onstream, possibly in late 2005. However, the industry is not resting on its laurels and is now studying ways to develop the massive gas reserves in this 'iceberg alley', writes *Jeff Crook.***

An estimate that was issued by the Canada-Newfoundland Offshore Petroleum Board (C-NOPB) on 19 May 2004 put the reserves and resources off the coast of Newfoundland and Labrador at 2.1bn barrels of oil and 9.6tn cf of gas. Of this, the Hibernia field holds 865mn barrels of oil and 1.32tn cf of gas, Terra Nova 354mn barrels and 44.9bn cf, and White Rose 283mn barrels and 2,722tn cf.

Further to the north, off the Labrador coast, the North Bjarni gas field holds 2.247tn cf of gas, while Gudri holds 924bn cf and Bjarni 863bn cf. Kevin Roche, Chair of the Board of Directors of the Newfoundland Ocean Industries Association (NOIA) said last year that development of these gas resources would be a 'smart move'. He added: 'The Alaskan and McKenzie Delta pipelines have recently received considerable attention. However, they represent complex solutions with a significant cost for moving gas from the arctic region on Canada's West Coast.'

Nevertheless, the production of gas off Newfoundland and Labrador presents a massive challenge, with operators having to cope with some of the harshest climatic conditions anywhere in the world – with dense fog, strong currents and stormy seas, as well as massive icebergs. The situation is exacerbated by the fact that icebergs tend to arrive in 'waves' rather than one-by-one. The largest of these icebergs, weighing up to 4,500,000 tonnes, plough deep ruts, thus posing a major risk to any E&P hardware on the seabed.

Roche has welcomed a reworking of old data into the effects of icebergs and scouring off Labrador for the Bjarni and North Bjarni fields, with the aim of gaining a broader understanding of how to harness the potential of these fields and the area as a whole. He believes that the prospects for gas development off Labrador depend very much on the development and implementation of new technologies.

Conventional offshore gas production would not appear practical in this region. A permanent gas production platform would be over-expensive, while the deep burial of long gas export pipelines, below the deepest iceberg ruts, would also be both difficult and expensive. A floating gas production facility might be practical, but very careful thought would need to be given to the design of a gas export system that would allow the facility to be moved when iceberg impact threatened.

The oil production facility built for Hibernia – the first development in the Jeanne d'Arc Basin – consisted of a massive gravity-based platform, surrounded by a protective barrier that was strong enough to resist the impact of the largest predicted icebergs. However, this proved immensely costly, so, for Terra Nova (the second development in the Basin) a more cost-effective solution was adopted involving a disconnectable floating production, storage and offloading (FPSO) vessel. A similar solution has been adopted for the White Rose field, whose facilities are designed to separate out and re-inject the associated gas as part of the oil production process.

The subsea Xmas trees for Terra Nova are located in excavations on the seafloor known as 'glory holes', with flexible risers and mooring lines attached to a buoy that floats just below the surface prior to the arrival of the FPSO. This buoy is pulled in and secured to the turret when the vessel arrives at its field site. The FPSO can be quickly disconnected on the approach of an iceberg and sail away under its own power (see *Petroleum Review*, September 2001 for further detail). A sophisticated safety management system must be implemented to protect these facilities from ice hazards.

## Ice management plan

Constant vigil is required to track icebergs, monitor ice sheets and forecast poor weather conditions. As the level of activity on the Grand Banks has increased, so a need has arisen for mutual support between operators to ensure a coordinated approach. This process is being fostered under the Grand Banks Ice Management Plan (GBIMP), the aim of which is to ensure that operations are carried out in a safe, efficient and environmentally responsible manner, with all necessary actions taken to ensure that wells and facilities are protected from hazardous ice situations. The plan encompasses mobile drilling units and support vessels in addition to the main field facilities.

Shorebase ice centres are provided for each development, to coordinate the collection of ice and iceberg data from a wide range of vessels and aircraft. These shore centres make arrangements for the aerial reconnaissance, with some data downloaded in near real-time to each installation and all data transferred to the centre at the end of each flight. In addition, it is the duty of each offshore unit to maintain a look-out for ice hazards. Radar is used to provide close-range detection for 'bergy bits' and 'growlers' as well as pack ice. Support vessels are deployed to maintain surveillance of larger icebergs, following patrol route instructions issued by the onshore ice centre.

One aim of the GBIMP is to ensure that each of the operator's computer systems is linked together in order to exchange data. This will create an integrated ice management computer system to provide one overall view of the current ice situation. All ice reports will be assigned a graded code depending on the time of sighting and reliability of report, to help the computer assimilate the data. The GBIMP calls for operators to consult one another to ensure that action taken by one operator does not adversely effect another – for instance, by deflecting a drifting iceberg from one facility to another. The plan also advocates the sharing of support vessels between operators when hazards threaten.

## White Rose development

The White Rose field lies 350 km east of Newfoundland, with recoverable reserves for the South Avalon pool estimated at between 200mn and 250mn barrels of oil at the time of the development application, which was sanctioned in March 2002. The field is operated by Husky Energy (72.5%), with partner Petro-Canada (27.5%), and will be developed by means of a disconnectable FPSO, under a similar concept to Terra Nova. The FPSO has been strengthened to resist the impact of an iceberg weighing up to 100,000 tonnes, but will disconnect from its moorings and sail to safety on the approach of a large iceberg. It is designed to produce 92,000 b/d of oil, with a storage capacity of 940,000 barrels.

Fabrication of the double-skinned hull of the White Rose field FPSO began in November 2002 at the Samsung Shipyard in South Korea, under a $140mn contract. The completed hull departed from the Korean yard in February 2004, arriving in Canadian waters during April 2004, after a 14,000 nautical-mile journey, for its final fitting out at the Aker Maritime Kiewit Contractors (AMKC) yard in Marytown, Newfoundland.

Fabrication of the topsides is currently underway at the AMKC yard as part of its $400mn installation, hook-up and commissioning contract. AMKC is a joint venture between Aker Kvaerner (49%) and its partner Peter Kiewit & Sons Co. (51%). The topsides design was completed in St John's Newfoundland, with around 80% of the topside design and fabrication person hours taking place in Newfoundland and Labrador, thus providing a major boost to the local economy.

A 1,000-tonne buoy will support flexible risers and mooring lines, and provide a fixed connection between the turret and the subsea production system. The buoy was fabricated by Single Buoy Mooring (SBM) in Abu Dhabi and will be installed during the course of the summer. On the approach of large icebergs the FPSO – to be known as *Sea Rose* – will disconnect from the buoy and move out of the path of the iceberg under its own propulsion. The propulsion system is duplicated for reliability, with power available at short notice from three marinised Rolls Royce RB-211 gas turbine generator sets.

Husky awarded a $250mn contract for the subsea production system to Technip CSO Canada, a Newfoundland-based affiliate of the Paris-based Technip Coflexip. The overall system includes a total of 42 km of flexible

## Commercial iceberg surveillance

Provincial Airlines performs commercial iceberg reconnaissance for the petroleum industry off the coast of Newfoundland. Its B-200 special missions aircraft is equipped with a wide range of instruments, including radar, with iceberg spotting confirmed by visual observation. Although based on a small executive jet, ice reconnaissance missions of over 1,000 miles are not uncommon. All data collected is automatically correlated into a real-time electronic map of regional ice conditions.

Provincial says that icebergs are not easy to detect by radar as they have a far lower profile than land or ships. The radar reflectivity of an iceberg is 1/60th of that of a steel ship, while detection is made more difficult due to the sea state and the physical shape of some icebergs. As a result, surveillance work involves a combination of sideways and forward-looking radar, visual survey and other tools, such as video cameras. Surveys are also carried out with an overlapping grid search pattern to ensure that areas are scanned from two directions.

Provincial Airlines says that around 85% of icebergs that reach the Grand Banks originate from the Tidewater glaciers along the west coast of Greenland. Between 10,000 and 15,000 icebergs are 'calved' each year from 20 major glaciers located between the Jacobshaven and Humbolt glaciers. Other sources of icebergs are East Greenland and Ellesmere Island. The icebergs often spend a year or more trapped in the pack ice filled bays of the Arctic islands until they eventually pass through the Davis Strait and into the Labrador current. Rarely do icebergs last more than one year south of this point.

Icebergs are carried along on the current and gradually diminish in size as their ice melts. However, prediction of iceberg movement is made difficult due to the effects of storms, wind and waves. The management of iceberg risks is also complicated by the fact that icebergs are rarely found singly, but more often in 'waves' of up to a 100. The approach that has been adopted off Newfoundland has thus been to divide the approach to the production facilities into three zones, with the charting of iceberg movements becoming more precise as the icebergs move close to the oil fields.

Survey results from the 'Regional Zone' to the north are used primarily to assess the iceberg risk for resource planning purposes for weeks to come. Then a start is made on building up a track history for each iceberg as they move southwards through the 'Confirmation Zone'.

In the most southerly 'Tracking Zone', the position of an iceberg is logged every couple of days as it approaches the oil fields, allowing the future movement of each iceberg to be predicted by computer. Where a potential problem is anticipated, a tug will be dispatched to carry out a more detailed survey and to monitor the position of any dangerous icebergs.

The tug can also take action when an iceberg is predicted to drift close to an oil facility. In the most hazardous scenarios, the floating oil facility will disconnect from its mooring and move clear while the iceberg drifts past the field site. In other cases it may be practical to deflect the iceberg. This can be achieved by applying a steady force over an extended distance of perhaps 30–40 km as the iceberg drifts southwards. Great care is required in applying this force, since icebergs tend to be unstable and can easily flip over, thus disconnecting, or tangling, the towline. Smaller icebergs can be deflected by firewater cannons or wash from the tugs propellers. ●

risers, flowlines and umbilicals, five manifolds and up to 21 Xmas trees and wellheads distributed in three glory hole sites on the seabed.

Meanwhile, three 9-metre-deep glory holes, to provide protection for the subsea equipment from iceberg scouring, have been excavated by Boskalis. Two of the glory holes were dredged in water depths of 115 to 130 metres using 'clam-dredging' technology, with the third excavated using a 'trailing-head suction-dredging system'. Completion of the glory holes is an important project milestone since it has allowed development drilling to get underway. Four production wells, four water injection wells and one gas injection well will be drilled prior to first oil. Delineation wells of a separate reservoir structure were completed earlier in 2003, indicating additional reserves of oil and gas.

The completed FPSO is expected to sail to the field site in 4Q2005, enabling production of the medium-weight 30° API crude oil to start in late 2005 or early 2006. The crude will be loaded by tandem mooring to shuttle tankers chartered from Knutsen OAS Shipping of Haugesund, Norway. Fiscal metering of the product will be performed by ultrasonic meters for the first time in this offshore sector.

The shuttle tanker contract covers a time-charter for two million-barrel capacity newbuild Suezmax-size tankers. One of tankers will be time-chartered for ten years, while the other is for five years. Both have options to extend the charter period. The dynamically-positioned (DP) double-hull vessels will also be constructed at Samsung Heavy Industries in South Korea. They will be specially winterised and equipped for operations on the Grand Banks.

### White Rose gas prospects

Last year, Husky said that the F-04 and F-04Z delineation wells drilled in a separate geological structure to the southern end of the White Rose field encountered 140 metres of gas and 40 metres of oil in the sandstone Avalon formation. The company added that early indications were that this had the potential to raise the estimated recovery of light oil by between 20mn and 30mn barrels, with 2,100bn cf of gas.

'The results from the F-04 and F-04Z wells are incremental to the White Rose oil field and have the potential to lengthen the production life and to improve the economic return on the project,' said John Lau, President and Chief Executive of Husky Oil. 'It is anticipated that the increase in the White Rose gas reserves will enhance the possibility for long-term gas development on the Grand Banks.'

To evaluate the gas prospects, in May 2004 Husky solicited expressions of interest from contractors and engineering firms to assess the key technical, economic and regulatory issues deemed critical to the safe and reliable natural gas development on the Grand Banks, as well as the capital and operating costs of such a development.

'Husky is pleased to commence the evaluation of this important resource,' said John Lau. 'This is the first step which may help realise gas production from White Rose within a decade. In order to evaluate natural gas development in the Jeanne d'Arc Basin, new technologies will need to be developed and, today, we believe this is possible.'

Husky said that its initial review of likely technologies indicates that a marine transportation using compressed natural gas/pressurised natural gas has potential. However, the company wishes to consider other technologies and is inviting proposals that encompass such technologies. ●

*Photos courtesy of Provincial Airways*

# US focus on gas development

**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 *Chesapeake Energy*.**

Chesapeake Energy is one of the six largest independent natural gas producers in the US, owning one of the country's largest inventories of domestic gas reserves. Including acquisitions announced or completed to May 2004, the company's estimated proved reserves are 3.8tn cfe (tn cf of gas equivalent). Chesapeake's current estimate for 2004 production is 341–347bn cfe, a projected increase over 2003 of 28%.

Approximately 89% of the company's reserves and projected production are natural gas, with some 80% of its assets being concentrated in the mid-continent region of the US and 20% in the Permian Basin region of western Texas and eastern New Mexico, the south Texas and Texas Gulf Coast regions, and the Ark-La-Tex Basin of east Texas and north Louisiana.

## Growing business

In 2003, Chesapeake generated net income of \$290.5mn, operating cash flow of \$903.9mn and EBITDA (earnings before interest, taxes, depreciation, and amortisation) of \$1,041.6mn on revenue of \$1,717.4mn. Oil and natural gas production for the full-year 2003 was 268bn cfe, an increase of 87bn cfe, or 48%, over the 181bn cfe produced in 2002. Of this 87bn cfe in year-over-year production growth, 36bn cfe was accounted for by internally generated organic drillbit growth, while 51bn cfe was generated from acquisitions. This makes the company's 2003 organic growth rate 20% – well above its forecast organic growth rate of 5% and among the top three organic growth performances reported by public mid- and large-sized E&P companies in the US.

Chesapeake has increased its production for 14 consecutive years. In addition, the 4Q2003 was the company's tenth consecutive quarter of sequential production growth. During the past ten quarters, Chesapeake's production has increased by 87%, representing an average sequential quarterly growth rate of 6.5% and an annualised growth rate of 28.1%.

Chesapeake began 2003 with estimated proved reserves of 2,205bn cfe and ended the year with 3,169bn cfe, an increase of 964bn cfe, or 44%. Taking into account production of 268bn cfe, reserve replacement during the year was 1,232bn cfe, or 459%, at a finding and acquisition cost of \$1.36/mn cfe.

## Reserves

Of the 1,232bn cfe of proved reserve additions, acquisitions added 805bn cfe at a cost of \$1.38/mn cfe, while drilling, including positive revisions to previous estimates, added 438bn cfe for a reserve replacement rate from drilling of 167% at a cost of \$1.32/mn cfe. Proved reserves sold during the year totalled 11bn cfe, at a price of \$2.07/mn cfe.

During last year Chesapeake drilled 442 operated wells and participated in another 641 wells operated by other companies. Drilling costs were \$438mn for operated wells and \$140mn for non-operated wells. The company's success rate was 96% for operated wells and 95% for non-operated wells.

## Mid-continent dominance

The mid-continent region is the third-largest natural gas supply area in the US and consists of Oklahoma, western Arkansas, the Texas Panhandle and southwest Kansas. The region is characterised by long-lived gas reserves with predictable and relatively low production depletion rates, and multiple geological targets that decrease drilling risk. Chesapeake dominates activity in the US mid-Continent – it is the number one gas producer and the number one driller of new wells in the region.

The company has assembled an estimated 3mn net acre leasehold inventory and acquired a 13,500 sq mile 3D seismic database across some of the highest potential deep natural gas provinces in North America. Since January 1998 Chesapeake has acquired an estimated 3.3tn cfe of proved natural gas reserves at an average cost of \$1.18/1,000 cfe.

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


Figure 1: a) US reserves and production comparison data b) Chesapeake's production (in mn cfe/d)


# Why invest in the biofuel market?

**_Andrew Owens_, Chairman of Green_ergy_, a leading supplier of low emission fuels to the UK domestic market, explains the rationale behind linking up with Novaol to build what is claimed to be the UK's first multi-feedstock biodiesel plant.**

The last five years have seen growing political interest in biofuels as one of the only practical ways of reducing transport-related greenhouse gas emissions in the short to medium term. Having introduced a 20 p/l (pence/litre) duty incentive for biodiesel in its 2002 Budget, the UK Government is currently consulting on additional fiscal and legislative measures to create a sizeable biodiesel market and industry in the UK. This responds to EU legislation, which sets indicative targets for biofuel consumption as a proportion of total diesel usage – starting at 2% of all fuel sales by energy content in 2005, to 5.75% of such sales in 2010.

Most significantly, the government is considering the concept of a biofuels obligation requiring all fuel suppliers to supply a proportion of their product as biofuel. There appears to be a growing body of support for the idea amongst MPs and in government circles, not least because it would avoid the need for long-term fiscal incentives.

## A shift towards low carbon products

Green_ergy_ has responded to these political drivers ahead of most, investing in the 'know-how' and technology to move the company on from supply of low pollution-based products to the supply of low carbon-based products.

The company's low carbon products are focused around blends containing



5% biodiesel – initially through Green*ergy* 'GlobalDiesel', with bioethanol blends likely to follow. In performance testing 5% biodiesel blends were found to offer the greatest environmental benefit. They also meet EN 590 standards and, therefore, engine warranty requirements. Although the company has invested in facilities to supply bespoke blends containing more than 5% biodiesel, these are expected to remain a niche product attractive to fleet users.

As well as offering low carbon fuel products, Green*ergy* identified early on an opportunity to own and operate low carbon infrastructure in the form of a biodiesel plant. Following two years of feasibility studies the company now plans to build a multi-feed biodiesel plant capable of producing 100,000 t/y of biodiesel, which is due to be commissioned in mid-winter 2005/2006.

## Becoming a biodiesel producer

Two years ago Greenergy began an investigation of the biodiesel markets in the UK and beyond, and of the various biodiesel production technologies available around the world. To make a commercial success of a biodiesel production plant, the company identified the following success factors:

- flexible feedstock mix,
- feedstock security,
- technology, and
- location.

Each was identified as critical to the success of the project.

## Feedstock mix

Green*ergy*'s early findings favoured a multi-feedstock approach to meet EN 14214 and concluded that the major source of feedstock would come from agricultural sources. Many biodiesel plant projects at this early stage in the market development are based around the processing of used cooking oil because it is a lower cost feedstock. However, Green*ergy* considers used cooking oil to be a useful pool extender and margin enhancer, rather than a base feedstock because (i) it is in limited availability and (ii) it is more difficult and expensive to process to EN 14214 than agricultural feedstocks such as rapeseed (pictured on previous page).

## Feedstock security

The potential shortage of economic feedstock supply was found to be one of the greatest risk factors for the project. To mitigate this risk Green*ergy* established a dedicated supply chain grouped around its Field to Forecourt™ farmers rapeseed contract, which is currently offered to farmers by Banks Cargill and Grainfarmers. Up to 75% of the plant's feedstock may come from the Field to Forecourt contract and supply chain, requiring up to 170,000 tonnes of seed.

In the first year (2003/2004 growing season) some 550 farmers committed to the contract, with each farmer typically supplying 100 tonnes of rapeseed. The target is to expand to the contract to 1,000 farmers for 2004/2005, and approximately 1,700 farmers for 2005/2006 and thereafter when the plant is up and running.

**Table 1** shows a simplified Field to Forecourt supply chain mass balance, excluding production consumables such as energy or transport. Essentially, rapeseed grown by farmers is crushed to recover crude rapeseed oil with the useful by-product of animal feed meal. The resultant crude oil, along with methanol, is then used as feedstock for the biodiesel plant producing biodiesel and the co-product glycerol.

Other feedstocks to be processed include used cooking oil (forecast to provide up to 10% of the plant's feedstock), with the balance being crude vegetable oils sourced from the UK or Europe depending on market conditions. A contract has already been concluded with Compass Group, who is to supply some 2,500 tonnes of used cooking oil for biodiesel production.

| | Inputs (tonnes) | Crush plant (tonnes) | Biodiesel production (tonnes) | Outputs (tonnes) |
|---|---|---|---|---|
| Seed from Field to Forecourt contract | 100 | (100) | – | – |
| Methanol from market | 4 | – | (4) | – |
| Meal | – | 57 | – | 57 |
| Crude vegetable oil | – | 43 | (43) | – |
| Biodiesel | – | – | 43 | 43 |
| Crude glycerol | – | – | 4 | 4 |
| Outputs | 104 | – | – | 104 |

Table 1: Simplified Field to Forecourt supply chain mass balance (excluding production consumables such as energy or transport)

# Biofuels for transport: an international perspective

'In the absence of strong government policies, we project that the worldwide use of oil in transport will nearly double between 2000 and 2030, leading to a similar increase in greenhouse gas emissions,' said Claude Mandil, Executive Director of the International Energy Agency (IEA) at the recent launch in Paris of the report *Biofuels for Transport: An International Perspective*. 'Biofuels, such as ethanol, biodiesel and other fuels derived from biomass could help change this picture, by offering an important low-greenhouse-gas alternative to petroleum over this time frame.'

The new IEA publication looks at recent trends in biofuel production and considers how the future may look if recent initiatives in IEA countries and around the world are fully implemented. It takes a global perspective on the nascent biofuels industry, assessing regional similarities and differences as well as the cost and benefits of the various biofuel options and technologies.

A major finding of the IEA's analysis is that recent policy initiatives, if fully implemented, could result in up to a 5% displacement of motor gasoline use with biofuel (mainly ethanol) worldwide by 2010. This would represent an important step. However, in OECD regions most of this production will likely be of conventional ethanol using grain feedstocks such as corn and wheat. While this type of biofuels production can provide important benefits, production costs are generally high and reductions in fossil energy use and carbon dioxide ($CO_2$) emissions are modest. Further, grain-based ethanol (as well as conventional oil-seed-based biodiesel) must compete for land with crop production for other purposes, such as for food and animal feed, and supplies are likely to be limited.

The study also reports that countries such as Brazil and India – that can grow and utilise sugar cane as a primary feedstock – are already producing relatively low-cost bioethanol with excellent characteristics. The high-yielding sugar cane that these countries use also provides sufficient crop waste to power the conversion of sugar to ethanol, virtually eliminating the need for fossil energy inputs and providing large 'well-to-wheel' reductions in $CO_2$. Since over the next two decades these and other developing countries may be able to produce more sugar cane ethanol than they need domestically, the IEA proposes that a global trade in biofuels be more rigorously pursued and identifies existing obstacles to this trade.

However, for the longer term, research into advanced biofuels production techniques is bearing fruit. It now appears likely that within a few years the first commercial-scale production facilities will be built to produce ethanol from cellulosic feedstocks such as crop wastes, grasses and trees, using far less fossil energy and providing much larger reductions in 'well-to-wheel' $CO_2$ emissions per litre of fuel than the current processes. Use of cellulosic feedstocks would also substantially increase potential biofuels supply. Advanced biomass conversion to synthetic diesel fuel is also under development, using gasification and other techniques, which could eventually allow commercial production of much higher yielding, low-greenhouse-gas biodiesel fuel.

The report reviews these important developments, but stresses that much greater government attention and support for demonstration and commercialisation of this 'next generation' of biofuels is needed in order to ensure that they succeed and that the potential benefits of biofuels use in the future are maximised. Overall, the analysis finds that the future for biofuels use around the world is bright, though current production practices in IEA countries fall short of maximising the potential benefits on offer. ●

## Technology

In line with its multi-feedstock approach Gree*nergy* selected proven multi-feedstock technology provided by Ballestra of Italy, a leading producer of oleo-chemicals and an experienced builder of biodiesel plant.

The project is partnered by Novaol, a leading European biodiesel producer with ten years' experience in the biodiesel market. Novaol has produced over 2mn tonnes of multi-feed biodiesel and offers valuable business experience and technology expertise for the plant. It is currently building a sister facility to the proposed Gree*nergy* plant in Livorno.

## Location

Whilst several site locations remain under review, the preferred location of the proposed plant is at Immingham on the Humber estuary, which offers unique logistical benefits, skill sets and commercial opportunities.

In identifying preferred sites the following criteria were paramount:

- A sea-fed location on the east or south coast of Great Britain, capable of effective logistics and trading with the important European vegetable oil and biodiesel markets.
- Near petroleum oil refineries to secure local markets.
- On a brownfield industrial site with existing labour force to keep infrastructure costs to a minimum.

Detailed engineering and design work is currently underway, co-funded by Gree*nergy* and Novoal. Project financing is expected to be completed over the summer so that construction can begin in September/October 2004. The plant is expected to enter production in winter 2005/2006.

## UK market prospects

Since launching biodiesel sales two years ago Greenergy has gained considerable experience in marketing biodiesel blends through its GlobalDiesel sales to local authority and fleet markets, as well as through forecourt partners such as Tesco and Sainsbury's. The company has established consumer demand for biodiesel blends even at a price premium, with many customers choosing the product because of its driveability and fuel consumption benefits as well as its environmental credentials. The capacity to sell GlobalDiesel on the retail forecourt as a second diesel grade will further increase as LRP volumes decline and the product is withdrawn.

This latest project is also backed by a Memorandum of Understanding for the supply of biodiesel to ConocoPhillips. The balance of the product produced by the new plant will be sold for export into the growing European biodiesel markets, which are themselves expanding to meet the EU Directive targets.

The current level of biodiesel demand is sufficient for Gree*nergy* to make a success of its 100,000 tonne plant. However, the opportunity exists to create a much larger market in the UK. Indeed, it is estimated that UK production could rise to as much as 1mn tonnes given the appropriate fiscal and/or regulatory environment. ●

energy INSTITUTE

# Seminar on Respiratory Protective Equipment – the facts about fit testing

**Friday 8 October 2004**
Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK

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

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

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

**www.energyinst.org.uk**

**Tickets:**
**Member: £40+VAT**
**Non member: £60+VAT**

**If you would like any further information on the programme or booking your place, please contact:**

**Faye Whitnall**
**t: +44 (0)20 7467 7116**
**f: +44 (0)20 7580 2230**

| Project | Location | Operator | Oil Peak Flows (kb/d) | Gas Peak Flows mn cf/d | Reserves mn/b | Partners and shareholdings |
|---|---|---|---|---|---|---|
| **Onstream 2003** | | | | | | |
| Amenam/Kpono | Nigeria | Total | 115 (2Q04) | | 500 | Total 30.4%, NNPC ??, ExxonMobil 10% |
| Bijupura-Salema | Brazil | Shell | 70 (03) | | 170 boe | Shell 80%, Petrobras 20% |
| Doba fields | Chad onshore | ExxonMobil | 225(04) | | 1,000 | ExxonMobil 40%, Petronas 35%, ChevronTexaco 25% |
| Ghawar Haradh PhII | Saudi Arabia onshore | Saudi Aramco | +300 | | | Saudi Aramco 100% |
| Grane | Norway | ExxonMobil | 220 (05) | | | ExxonMobil 26% |
| AOSP Muskeg River (Tars'n) | Canada Athabasca | Shell | 155 (04) | | 1700 boe | Shell Canada 60%, Chevron Canada 20%, Western Oil Sands 20% |
| Nakika | GoM | Shell | 100 | 425 | 300 boe | Shell 50%, BP 50% |
| Su Tu Den (Black Lion) | 15Vietnam Cuu Long Bas | ConocoPhillips | 95 (04) | | 400 | ConocoPhillips 23.5%, Petrovietnam 50% |
| Zafiro S'th'n, (Exp Area(SEA) | Equatorial Guinea | ExxonMobil | +110 | | 150 | ExxonMobil(MEG) 71.25%, Devon Energy 23.75%, Equat Guinea Govt 5% |
| **Onstream 2004** | | | | | | |
| Abu Sa'fah (expansion) | Saudi Arabia offshore | Saudi Aramco | +150 | 7,000 | | Saudi Aramco 100% |
| Albacora Leste | Brazil | Petrobras | 180 (09) | 1,507 boe | | Petrobras 90%, Repsol 10% |
| Bab North East | Abu Dhabi onshore | ADCO | +100 (04) | | | ADCO 100% |
| Barracuda-Caratinga | Brazil | Petrobras | 273 (06) | 1,778 boe | | Petrobras 100% |
| Bayu-Undan PhI (liquids) | ZOCA | ConocoPhillips | 115 | (950 inj | 400 (cond) | ConocoPhillips 56.72%, Eni 12.04%, Santos 10.64%, INPEX 10.53%, TokyoElect/Gas 10.08% |
| Caofedian | China Bohai Gulf | Kerr McGee | 100 | | | Kerr McGee |
| Clair South | UKCS Wof Shetland | BP | 80(05) | 15 | 250 | BP 28.6%, ConocoPhillips 24%, ChevronTexaco 19.4%, Shell 18.7%, Amerada 9.3% |
| Elephant NC-174 | Libya onshore | Eni | 150 (06) | 760 | | Libya's NOC 50%, Eni 33.34%, Korean Consortium 16.66% |
| Hamaca (Orinoco Hvy oil) | Venezuela | Petrolera Ameri | 190 | | | ChevronTexaco 60%, ConocoPhillips 40% |
| Holstein | GoM | BP | 100 | 290 | 500-1,000 bo | BP 50%, Shell 50% |
| Karachaganak PhII | Kazakhstan onshore | Eni and BG | +100(04) | 1,400 | 2,400 (liqs | Eni 32.5%, British Gas 32.5%, ChevronTexaco 20%, Lukoil 15% |
| Kizomba A (Hungo/Chocalho) | Angola | ExxonMobil | 250 | 1,000 boe | | ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33% |
| Marco Polo | GoM | Anadarko | 100 | 180 | | Anadarko |
| Marlim Sul II | Brazil | Petrobras | 100 | 80 | 2,679 boe (t | Petrobras 100% |
| Priobskoye | Russia Siberia | Yukos | +350 | | 4,000 | Yukos 100%? |
| Qatif field expansion | Saudi Arabia onshore | Saudi Aramco | +500 | | 8,000 | Saudi Aramco 100% |
| Roncador II | Brazil | Petrobras | 140 (08) | | 2,000 boe (tot) | Petrobras 100% |
| Soroush/Nowruz | Iran expansion | Shell | 130 | | | |
| **Onstream 2005** | | | | | | |
| ACG magastructure PhI | Azerbaijan | BP | 400 (06) | | 6,000+ | BP 34.14%, Unocal 10.28%, Socar 10%, Inpex 10%, Statoil 8.56%, ExxonMobil 8% |
| (Azeri-Chirag-Guneshli) | | | | | | TPAO 6.75%, Devon 5.62%, Itochu 3.92%, Delta Hess 2.72% |
| Bonga (OML 118) | Nigeria | Shell | 225 | 170 | 600 | Shell 55%, ExxonMobil 20%, Total 12.5%, Agip 12.5% |
| Corocoro PhI | Venezuela offshore | ConocoPhillips | 50 | | 450 | ConocoPhillips 50%, PDVSA 24%, Eni 26% |
| Darkhovin | Iran | Eni/Naftiran | 180 | | | |
| Greater Angostura PhI | Trinidad | BHP Billiton | 80 | | up to 300 | BHP Billiton 45%, Total 30%, Talisman Energy 25% |
| Jubarte+Cachalote? | Brazil B60 Santos | Petrobras | 60+50? | | 600+300? boe | Petrobras 100%? |
| Mad Dog | GoM | BP | 80 | 40 | 250 boe | BP 60.5%, BHP Billiton 23.9%, Unocal 15.6% |
| Marlim Leste | Brazil | Petrobras | 100 (07) | | ? | Petrobras 100% |
| Mutineer-Exeter (Cnvr Bas | NW Australia | Santos | 100 (07) | 3 | 100 | Santos ? |
| NEAD project | NE Abu Dhabi | Adnoc | +160 | | | ADNOC 100%? |
| Prirazlomnoye | Russia Siberia | Gazprom/Rosneft | 155 (10) | | 600 | Gazprom ?, Rosneft? |
| Roncador III | Brazil | Petrobras | 145 (08) | | 2,000 boe (tot) | Petrobras 100% |
| Sakhalin I (Chayvo field) | Russian Far East | ExxonMobil | 250 | 1,000 | 2,300 | Exxon NG 30%, Sakhalin O&G 30%, ONGC Videsh 20%,SakhMNG 11.5%, RB-Astra 8.5% |
| Salym fields-W,Upp,Vadely | Khanty-Mansiisk | Shell/Evikhon | 120 (09)boe | | 600 | Salym Petroleum Development NV (SPD): 50% Shell, 50% OAO Evikhon |
| Sanha(cond), Bomboco(crude) | Angola | ChevronTexaco | 100 boe(06) | | | |
| Syncrude PhIII | Athabasca, Canada | | 100 | | | |
| Thunder Horse (inc. North | GoM | BP | 250 | 200 | 1,500 boe | BP 75%, ExxonMobil 25% |
| White Rose | Eastern Canada | Husky Oil | 100(06) | | 230 | Husky Oil 72.5%, PetroCanada 27.5% |
| **Onstream 2006** | | | | | | |
| ACG magastructure PhII | Azerbaijan | BP | to 600 (07) | | 6,000+ | See under PhI in 2005 |
| Atlantis | GoM | BP | 150 | | 675 boe | BP 56%, BHP 44% |
| Banyu Urip (Cepu block) | Indonesia Offshore | ExxonMobil | 165 | 20 | 2,000 in block | Under negotiation |
| Benguela-Belize (BBLT1) | Angola | ChevronTexaco | 100 | | 400 | ChevronTexaco 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9% |
| Bu Hasa development proj | Abu Dhabi | Adco | 250 | | | ADCO 100% |
| Buzzard | UKCS | Encana | 200 (07/08) | | 550 | Encana 43%, Intrepid Energy 30%, BG Group 22%, Edinburgh Oil & Gas 5% |
| Chinguetti PhI | Mauritania offshore | Woodside | 75 | | 120 | Woodside 53.846%, Hardman Res 21.6%, Roc Oil 3.693%, Premier 9.231%, BG 11.63% |
| Dalia | Angola | Total | 240 | | 1,600 | Total 40%, BP 16.67 %, Statoil 13.33%, ExxonMobil 20% |
| Enfield (+Laverda/Vincen | Australia NW | Shelf Woodside | 100 | | 363 | Woodside Petroleum 60%, Mitsui 40% |
| Erha | Nigeria (OPL 209) | ExxonMobil | 150 | | 500 | ExxonMobil 56.25%, Shell 43.75% |

Future oilfield projects with a peak production capacity of over 100,000 b/d

| Project | Location | Operator | Oil Peak Flows (kb/d) | Gas Peak Flows mn cf/d | Reserves mn/b | Partners and shareholdings |
|---|---|---|---|---|---|---|
| Frade | Brazil | ChevronTexaco | 110 (07) | | 300 | ChevronTexaco 42.5%, Petrobras, Nissho Iwai |
| Ghawar Haradh PhIII | Saudi Arabia onshore | Saudi Aramco | +300 | | | Saudi Aramco 100% |
| Kizomba B (Kissanje/Dikan | Angola | ExxonMobil | 250 | | 1,000 | ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33% |
| Kristin | Norway | | 140 (cond 500 | | | ExxonMobil 11% ????? |
| Marlim Sul III | Brazil | Petrobras | 100 (07) | | 2,679 boe (tot) | Petrobras 100% |
| Surmont (heavy oil) | Canada N. Alberta | ConocoPhillips | 100 (12) | | ? | ConocoPhillips 43.5%, Total 43.5%, Devon 13% |
| Tengiz/Kololev expansion* | Kazakhstan | ChevronTexaco | 285 to 45 | 100 | 7,000 | ChevronTexaco 50%, ExxonMobil 25%, KazMunaiGaz 20%, LukArco 5% |
| Usan/Ukot/Tongo | Nigeria (OPL 222) | Elf Nigeria (To | 115 | | | Elf Nigeria %, ChevronTexaco %, ExxonMobil 30%, Nexen % |
| **Onstream 2007** | | | | | | |
| Agbami | Nigeria OPL 216, 217 | ChevronTexaco | 250 (07/8) | | | NNPC 50%, ChevronTexaco 32%, Petrobras 8%, Famfa 10% |
| Akpo | Nigeria OPL 246 | Elf Nigeria (Total) | 100 | | 625 boe | Total |
| Azadegan (southern part) | onshore Iran | NIOC/Inspex | 260(09) | | 2,500-3,000 | NIOC 25%, Japanese interests 75% (Inspex %, Japex %, JNOC %, Tomen %) |
| Bonga South + Aparo? | Nigeria (OML 118) | Shell+ChevTex | 250 | | 1,000 | Shell 55%, ExxonMobil 20%, Total 12.5%, Eni 12.5% |
| Greater Plutonio (6 field | Angola block 18 | BP | 220 | | 800 | BP 50%, Shell 50% |
| Lobito-Tombuco (BBLT 2) | Angola | ChevronTexaco | 100 (08) | | 400 | ChevronTexaco 31%, Agip 20%, Total 20%, Sonangol 20%, Galp 9% |
| Tahiti | GoM | ChevronTexaco | 150? | | 500mn boe | ChevronTexaco 58%, Encana 25%, Shell 17% |
| Vankorskoye 2 fields | Russia Siberia | Shell/TFE PSA | 216 | | 900 | |
| **Onstream 2008** | | | | | | |
| ACG magastructure PhIII | Azerbaijan | BP | to 1000 (11) | | 6000+ | See under PhI in 2005 |
| Horizon (tar sand) | Canada | CNR | 232 (08) | | | CNR ??? |
| Kashagan PhI | Kazakh Caspian | Agip (Eni) | 450 (09) | 1,500 | 13,000 | Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33% |
| Kizomba C(Mondo,Saxi,Batu | Angola | ExxonMobil | 250 | | 1,000 | ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33% |
| Marlim Sul IV | Brazil | Petrobras | 120 (07) | | 2,679 boe (tot) | Petrobras 100% |
| Su Tu Trang (White Lion)1 | Vietnam Cuu Long Bas | ConocoPhillips | 100? | | 220 | Petrovietnam 50%, ConocoPhillips 23.25%, KNOC 14.25%, SK Corp 9%, Geopetrol 3.5% |
| **Onstream 2009** | | | | | | |
| Pearl GTL (PhI) | Qatar | Qatar Shell Gas | 70 | | 800 | Qatar Petroleum?%, Shell ?% |
| Karachaganak PhIII&IV | Kazakhstan | Eni and BG | +200? | | | Eni 32.5%, British Gas 32.5%, ChevronTexaco 20%, Lukoil 15% |
| Khursaniyah, Abu Hadriya | S Arabia onshore | Saudi Aramco | +500 | | 4,500 & 500 | Saudi Aramco 100% |
| **Onstream 2010** | | | | | | |
| Kashagan PhII | Kazakh Caspian | Agip (Eni) | 900 (12) | 1,500 | 13,000 | Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33% |
| **Onstream 2011** | | | | | | |
| Pearl GTL PhII | Qatar | Qatar Shell Gas | 70 | | | Qatar Petroleum?%, Shell ?% |
| **Onstream 2012** | | | | | | |
| Kashagan Ph3 | Kazakh Caspian | Agip (Eni) | 1,200(15) | 1,500 | 13,000 | Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33% |
| **Potential Projects** | | | | | | |
| Ahwaz Bangestan Devs | onshore Iran | NIOC/? | | 350 | | |
| Arash | Iran in Gulf | NIOC | 683 boe | | | |
| Azadegan (Northern part) | onshore Iran | NIOC/? | | 400 | 2,500–3,000 | |
| Block 09-03 | Vietnam Cuu Long Bas | Petrovietnam | | 100+? | 300–400 | |
| Great White | GoM | Shell | | | 500–1000 boe | Shell?? |
| Kharyaga | Russia Siberia | Total PSA | | | 5,200 | |
| Khvalynskoye | Russian Caspian | Lukoil/KazMgaz | | | 627 boe | |
| Khurais | Saudi Arabia onshore | Saudi Aramco | 1000+ | | 3,000 | Saudi Aramco 100% |
| Kirkuk Khurmala Dome Dev | Iraq onshore | NOC | 100 | | | |
| Kurmangazy | N Caspian (Russ/Kaz) | Rosneft/KMG | | | | Rosneft 25%, Other Russian 25%, KazMunaiGaz 25%, Toal 25% (tbc) |
| Kushk | Iran | NIOC | | | 1,000 boe | |
| Long Lake (in-situ tarsan | Canada | Nexen | | | | |
| Lungu | China Tarim Basin | Petrochina | 500 | | | |
| Manifa (Arab Heavy) | Saudi Arabia onshore | Saudi Aramco | | 300 | | Saudi Aramco 100% |
| Majnoon | Iraq onshore | SOC | | 360 | | |
| Nuayyim (Arab Super Light) | Saudi Arabia onshore | Saudi Aramco | | 75 | 250 | Saudi Aramco 100% |
| Northern Fields Project | Kuwait | KOC/? | 400 | | | |
| Northern Territories 4fld | Russia Timan-Pechora | Lukoil, ConocoPhillips | | | 990 | |
| Suncor (tarsands) | Canada | | | 100 | | |
| Talanskoye | Russia Siberia | Surgutneftegas | 832 | | | |
| Tsentralnoye block | Russia/Kazakh Caspian | Lukoil/Kazakhoil | | | 3,800 | TsentrKaspneftegaz JV: Kazakhoil 50%, Lukoil and Gazprom 50% |
| Val Gamburtsev | Russia Siberia | Yukos/Sibneft | | | | 600 |
| Verkhnechonsknoye | Eastern Siberia | TNK-BP? | | | | 1,500 |
| Yalamo-Samur | Russia/Azeri Caspian | Lukoil | | | | 3,750 boe |
| Yuri Korchagin | Russian Caspian | Lukoil | | | | 8,79 boe |
| Yuzhno-Shapinskoye | Russia Siberia | SeverTek | | | 500 | Lukoil Fortum |
| West Qurna PhII | Iraq onshore | SOC | | 650 | | |

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# Depletion now running at over 1mn b/d

**This year's *BP Statistical Review of World Energy* once again provides a mine of information for those wishing to analyse the energy industries. *Chris Skrebowski* has used this year's data to try to analyse the impact that declining production is now having.**

Last year *Petroleum Review* (August 2003) re-presented the BP production statistics, dividing them into producers in decline, Opec producers with growth potential and non-Opec producers with growing output. This year, the re-presentation of the latest (June 2004) BP statistics has been done as a continuum of producers from those with the largest declines to those with the largest gains. To damp out individual year bias the listing has been based on the average annual change in production over the last two years of data, ie the average of the 2001/2003 output changes. One- and three-year average changes are also listed in **Table 1** and it can be seen that decline/increase order changes only slightly depending on the period used.

Production declines for entire countries, as opposed to individual fields or regions, is a recent phenomenon. Until the 1990s the only countries in decline had been the US, which moved into continuous decline after 1985 (although peak production was actually in 1971), and Romania, that also peaked in 1985. By the late 1990s, however, the BP statistics were showing at least 10 significant producers in decline; 1999 added two more, as did 2000 and 2001.

The most dramatic change to be seen in the latest BP statistics is the way the 32 countries where production is still expanding are having to produce ever faster to make up for the 18 countries where decline is into at least its third year. Overall production growth in 2003 at 2.71mn b/d (3.66%) was one of the five largest annual volume increments seen since 1973. However unlike all the earlier production surges, countries with declining output were a significant factor in 2003. Because the 18 countries in sustained decline 'lost' production of 1.14mn b/d (–4.91%) this meant those still expanding had to increase production by 3.82mn b/d (7.52%) in order to achieve an overall production growth of 2.71mn b/d (3.66%).

Apart from the 18 in clear decline it is too early to be confident about which other producers will join them. Denmark looks a likely candidate and China looks to be another, the Chinese Government having confirmed that the two largest producing regions – Daqing and Shengli – are now in decline.

The rapid fall in Iraqi production is clearly a special case. Similarly, the small decline in Nigerian production is exceptional, reflecting the impact of recent social and political strife.

Two countries that had appeared to be in decline – Syria and India – have recovered over recent years, but it is unclear if this is sustainable. Similarly, Egypt has almost stabilised production following a period of steady decline.

Venezuela presents a real enigma. The reserves are generally thought to be available but a sustained lack of investment and the more recent political problems mean Venezuelan production has actually been declining since 1998 – despite the start-up of the four heavy oil projects in the Orinoco tar belt.

It should also be noted that, in totalling volumes in decline, Nigeria and Iraq have been excluded from the calculations.

## Impact of decline

Production from the 18 producers now in obvious decline actually peaked in 1997 at 24.7mn b/d and by 2003 their production had fallen to 22.1mn b/d. All the signs are that the rate of decline among the countries is actually rising. Decline among the group had been running at over 0.5mn b/d in 1998/1999 but recovered in 1999/2000 to post a gain of over 100,000 b/d, which was largely because Australian and Norwegian production surged. Since 2000, however, decline appears to have steadily escalated, with group production falling by over 500,000 b/d in 2001, by over 400,000 b/d in 2002 and by a stunning 1.1mn b/d in 2003 (see **Table 1**).

Calculation of the annual average decline rate shows that in the 18 years since the US went into continuous decline (in 1985) it has been losing an average of 1.6%/y, which is probably the reason why people have generally been fairly relaxed about depletion, assuming it progresses slowly. This view may be misplaced as, for example, Indonesia, in its 12 years of decline, has averaged 2.6%/y but over the last few years this has accelerated to last year's 8.5%.

Although it is generally true that decline rates for predominantly offshore producers are faster than for land-based production, there are notable exceptions. In the period since peak, Oman's production has declined by over 7%/y, Australia's by 7.6%/y, Colombia's by 8.2%/y, and UK production by 5.6%/y. Among the smaller producers there is wide range of gains and losses, but care needs to be taken as the performance of a single field can have a disproportionate impact.

Comparing average annual percentage changes over one, two and three years clearly indicates that, for the majority of the producers in decline, the rate of decline is increasing. The most dramatic example is Gabon, where, averaged over the last three years, decline is running at over 8%/y – but over the last year by over 18%. This and the other data tends to undermine the widely held view that decline rates tend to slow as depletion progresses.

Sustained large-scale production decline by an increasing numbers of countries means that the burden on countries with expansion potential increases, as the volumes lost to depletion have to be made up before any incremental demand can be met.

*continued on p48...*

| Average % decline/gain 2003/2001 | Country and Peak production year | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | %Change 1 year 2003/2002 | %Change 3-year av 2003/2000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *–21.66* | *Iraq* | *530* | *580* | *1,166* | *2,126* | *2,541* | *2,583* | *2,371* | *2,030* | *1,344* | *–33.79%* | *–15.99* |
| –10.13 | Gabon –1996 | 356 | ***365*** | 364 | 337 | 340 | 327 | 301 | 295 | 240 | –18.64% | –8.87 |
| –7.56 | Indonesia –1991 | 1,578 | 1,580 | 1,557 | 1,520 | 1,408 | 1,456 | 1,389 | 1,288 | 1,179 | –8.46% | –6.34 |
| –7.50 | Cameroon –1997 | 106 | 110 | ***124*** | 105 | 95 | 88 | 80 | 72 | 68 | –5.56% | –7.58 |
| –7.44 | Australia – 2000 | 583 | 610 | 668 | 644 | 625 | ***809*** | 733 | 731 | 624 | –14.64% | –7.62 |
| –7.18 | Oman – 2001 | 868 | 897 | 909 | 905 | 911 | 959 | ***961*** | 900 | 823 | –8.56% | –4.73 |
| –5.17 | Congo (Brazz) | 180 | 200 | 225 | 264 | ***293*** | 275 | 271 | 259 | 243 | –6.18% | –3.88 |
| –5.02 | Colombia – 1999 | 591 | 635 | 667 | 775 | ***838*** | 711 | 627 | 601 | 564 | –6.16% | –6.89 |
| –4.66 | UK – 1999 | 2,749 | 2,735 | 2,702 | 2,793 | ***2,893*** | 2,657 | 2,476 | 2,463 | 2,245 | –8.85% | –5.17 |
| –3.80 | Venezuela – 1970 | 2,959 | 3,137 | 3,321 | ***3,510*** | 3,248 | 3,321 | 3,233 | 3,218 | 2,987 | –7.18% | –3.35 |
| –3.52 | Tunisia – 1992 | 90 | 89 | 81 | 83 | 84 | 78 | 71 | 73 | 66 | –9.59% | –5.13 |
| –3.06 | Peru – 1994 | 123 | 121 | 120 | 119 | 110 | 104 | 98 | 98 | 92 | –6.12% | –3.85 |
| –2.69 | Romania – 1985 | 145 | 142 | 141 | 137 | 133 | 131 | 130 | 127 | 123 | –3.15% | –2.04 |
| –2.28 | Norway – 2001 | 2,903 | 3,233 | 3,280 | 3,139 | 3,139 | 3,343 | ***3,416*** | 3,329 | 3,260 | –2.07% | –0.83 |
| –2.17 | Argentina –1998 | 758 | 823 | 877 | ***890*** | 847 | 819 | 829 | 808 | 793 | –1.86% | –1.06 |
| –1.80 | Yemen – 2001 | 351 | 357 | 375 | 380 | 405 | 450 | ***471*** | 462 | 454 | –1.73% | 0.30 |
| –1.46 | Uzbekistan – 1999 | 172 | 174 | 182 | 191 | ***191*** | 177 | 171 | 171 | 166 | –2.92% | –2.07 |
| –1.40 | US – 1971/1985 | 8,322 | 8,295 | 8,269 | 8,011 | 7,731 | 7,733 | 7,669 | 7,626 | 7,454 | –2.26% | –1.20 |
| –0.53 | Egypt – 1993 | 924 | 894 | 873 | 857 | 827 | 781 | 758 | 753 | 750 | –0.40% | –1.32 |
| *–0.32* | *Nigeria* | *1998* | *2,138* | *2,303* | *2,163* | *2,028* | *2,104* | *2,199* | *2,013* | *2,185* | *8.54%* | *1.28* |
| **Total decline (excl Iraq and Nigeria)** | | **23,758** | **24,397** | **24,735** | **24,660** | **24,118** | **24,219** | **23,684** | **23,274** | **22,131** | **–4.91%** | **–2.87** |
| Change from year earlier | | – | 639 | 338 | –75 | –542 | 101 | –535 | –410 | –1143 | – | – |
| % change on year | | – | 2.69 | 1.39 | –0.30 | –2.20 | 0.42 | –2.21 | –1.73 | –4.91 | – | – |
| 0.00 | other Mid East | 52 | 50 | 50 | 49 | 48 | 48 | 48 | 48 | 48 | 0.00% | 0.00 |
| 0.83 | India – 1995? | ***804*** | 778 | 800 | 791 | 788 | 780 | 780 | 794 | 793 | –0.13% | 0.56 |
| 0.94 | Syria – 1995? | ***596*** | 586 | 577 | 576 | 579 | 550 | 583 | 572 | 594 | 3.85% | 2.67 |
| 1.32 | Ecuador | 395 | 393 | 397 | 384 | 382 | 409 | 416 | 410 | 427 | 4.15% | 1.47 |
| 1.36 | China | 2,989 | 3,170 | 3,211 | 3,212 | 3,213 | 3,252 | 3,306 | 3,346 | 3,396 | 1.49% | 1.48 |
| 1.58 | Iran – 1974 | 3,744 | 3,759 | 3,776 | 3,855 | 3,603 | 3,818 | 3,734 | 3,420 | 3,852 | 12.63% | 0.30 |
| 1.85 | UAE | 2,410 | 2,495 | 2,490 | 2,558 | 2,302 | 2,499 | 2,430 | 2,159 | 2,520 | 16.72% | 0.28 |
| 2.14 | other Euro/Eurasia | 576 | 548 | 526 | 507 | 475 | 466 | 467 | 483 | 487 | 0.83% | 1.50 |
| 2.17 | Azerbaijan | 185 | 183 | 185 | 230 | 278 | 281 | 300 | 311 | 313 | 0.64% | 3.80 |
| 2.21 | Libya –1970 | 1,439 | 1,452 | 1,489 | 1,480 | 1,425 | 1,475 | 1,425 | 1,376 | 1,488 | 8.14% | 0.29 |
| 2.32 | other Asia-Pacific | 231 | 246 | 228 | 218 | 219 | 198 | 194 | 200 | 203 | 1.50% | 0.84 |
| 2.71 | Brunei – 1979 | 175 | 165 | 163 | 157 | 182 | 193 | 203 | 210 | 214 | 1.90% | 3.63 |
| 3.03 | Denmark – 2002? | 188 | 207 | 233 | 235 | 301 | 364 | 347 | ***372*** | 368 | –1.08% | 0.37 |
| 3.14 | Vietnam | 155 | 179 | 205 | 245 | 296 | 328 | 350 | 354 | 372 | 5.08% | 4.47 |
| 3.22 | Mexico | 3,065 | 3,277 | 3,410 | 3,499 | 3,343 | 3,450 | 3,560 | 3,585 | 3,789 | 5.69% | 3.28 |
| 3.69 | Qatar | 461 | 568 | 694 | 747 | 797 | 855 | 854 | 783 | 917 | 17.11% | 2.42 |
| 4.08 | Kuwait | 2,130 | 2,129 | 2,137 | 2,176 | 2,000 | 2,105 | 2,069 | 1,871 | 2,238 | 19.62% | 2.11 |
| 4.59 | Saudi Arabia | 9,032 | 9,180 | 9,361 | 9,370 | 8,694 | 9,297 | 8,992 | 8,664 | 9,817 | 13.31% | 1.86 |
| 5.05 | Canada | 2,402 | 2,480 | 2,588 | 2,672 | 2,604 | 2,721 | 2,712 | 2,838 | 2,986 | 5.21% | 3.25 |
| 5.66 | Malaysia | 724 | 736 | 764 | 815 | 791 | 791 | 786 | 828 | 875 | 5.68% | 3.54 |
| 7.81 | other Africa | 51 | 62 | 64 | 63 | 56 | 61 | 64 | 65 | 74 | 3.85% | 7.10 |
| 8.04 | Brazil | 718 | 807 | 868 | 1,003 | 1,133 | 1,268 | 1,337 | 1,499 | 1,552 | 3.54% | 7.47 |
| 9.06 | other L America | 96 | 102 | 108 | 125 | 122 | 129 | 138 | 153 | 163 | 6.54% | 8.79 |
| 9.44 | Algeria | 1,327 | 1,386 | 1,421 | 1,461 | 1,515 | 1,578 | 1,562 | 1,681 | 1,857 | 10.47% | 5.89 |
| 9.64 | Angola | 633 | 716 | 741 | 731 | 745 | 746 | 742 | 905 | 885 | –2.21% | 6.21 |
| 10.37 | Trin & Tob – 1978 | 142 | 141 | 135 | 134 | 141 | 138 | 135 | 155 | 163 | 5.16% | 6.04 |
| 10.43 | Sudan | 2 | 5 | 9 | 12 | 63 | 174 | 211 | 233 | 255 | 9.44% | 15.52 |
| 10.54 | Russian Fed –1987 | 6,288 | 6,114 | 6,227 | 6,169 | 6,178 | 6,536 | 7,056 | 7,698 | 8,543 | 10.98% | 10.24 |
| 12.36 | Thailand | 87 | 97 | 116 | 121 | 132 | 164 | 174 | 191 | 217 | 13.61% | 10.77 |
| 14.81 | Turkmenistan | 84 | 90 | 108 | 129 | 143 | 144 | 162 | 182 | 210 | 15.38% | 15.28 |
| 16.15 | Kazakhstan | 434 | 474 | 536 | 537 | 631 | 744 | 836 | 1,018 | 1,106 | 8.64% | 16.22 |
| 17.72 | Italy – 1997 | 101 | 104 | ***114*** | 108 | 96 | 88 | 79 | 106 | 107 | 0.94% | 7.20 |
| 18.78 | Equatorial Guinea | 7 | 17 | 60 | 83 | 100 | 113 | 181 | 237 | 249 | 5.06% | 40.12 |
| **Total incr + Iraq, Nigeria** | | **44,251** | **45,414** | **47,260** | **48,741** | **47,944** | **50,450** | **50,803** | **50,790** | **54,607** | **7.52%** | **2.75** |
| Change on year | | – | 1,163 | 1,846 | 1,481 | –797 | 2,506 | 353 | –13 | 3,817 | – | – |
| % change on year | | – | 2.63 | 4.06 | 3.13 | –1.64 | 5.23 | 0.70 | –0.03 | 7.52 | – | – |
| Regional Totals | | | | | | | | | | | | |
| 1.03 | Total N America | 13,789 | 14,052 | 14,267 | 14,182 | 13,678 | 13,904 | 13,941 | 14,049 | 14,229 | 1.28 | 0.78 |
| –0.53 | Total L America | 5,782 | 6,159 | 6,493 | 6,940 | 6,822 | 6,899 | 6,813 | 6,942 | 6,741 | –2.90 | –0.76 |
| 4.81 | Total Euro/Asia | 13,825 | 14,004 | 14,233 | 14,175 | 14,458 | 14,932 | 15,441 | 16,259 | 16,927 | 4.11 | 4.45 |
| 0.21 | Total M East | 20,130 | 20,555 | 21,564 | 22,742 | 21,880 | 23,163 | 22,512 | 20,909 | 22,607 | 8.12 | –0.80 |
| 3.40 | Total Africa | 7,112 | 7,434 | 7,754 | 7,638 | 7,571 | 7,800 | 7,866 | 7,962 | 8,401 | 5.51 | 2.57 |
| –0.27 | Total Asia-Pacific | 7,325 | 7,571 | 7,713 | 7,724 | 7,654 | 7,971 | 7,914 | 7,943 | 7,872 | –0.89 | –0.41 |
| –0.34 | OECD | 20,737 | 21,356 | 21,665 | 21,477 | 21,082 | 21,504 | 21,330 | 21,402 | 21,185 | –1.01 | –0.49 |
| 0.21 | OPEC | 27,607 | 28,387 | 29,743 | 30,965 | 29,561 | 31,090 | 30,258 | 28,503 | 30,383 | 6.60 | –0.76 |
| 0.49 | non-Opec excl FSU | 33,013 | 34,245 | 34,904 | 35,044 | 34,951 | 35,565 | 35,570 | 36,049 | 35,917 | –0.37 | 0.33 |
| 10.50 | FSU | 7,297 | 7,171 | 7,377 | 7,391 | 7,551 | 8,013 | 8,659 | 9,513 | 10,477 | 10.13 | 10.25 |
| **1.54** | **Total World** | **68,008** | **69,803** | **72,024** | **73,400** | **72,063** | **74,669** | **74,487** | **74,065** | **76,777** | **3.66** | **0.94** |
| Change on year | | – | 1,795 | 2,221 | 1,376 | –1,337 | 2,606 | –182 | –422 | 2,712 | – | – |
| % Change on year | | – | 2.64 | 3.18 | 1.91 | –1.82 | 3.62 | –0.24 | –0.57 | 3.66 | – | – |

*Source:* BP Statistical Review June 2004: *Re-presentation and calculations by* Petroleum Review

*NB: All percentage changes calculated on b/d numbers, unlike BP, who uses the metric tonne numbers for percentage change calculations*

*Bold italic figures are peak production years*

**Table 1: World oil and liquids production 1995–2003**

# Growing global LPG tanker fleet


Photo courtesy of Bergesen dy ASA

***David Hayes* takes a closer look at the LPG shipping sector and the forces driving a global fleet expansion.**

The forecast growth in demand for LPG, ammonia and other similar gases in China and the rest of Asia is expected to lead to an increase in shipyard orders for LPG tankers over the next few years. In addition, at the same time that shipping companies are expected to begin expanding their gas carrier fleets to supply increasing LPG export volumes from the Middle East to the Far East, a significant proportion of the world's existing LPG tanker fleet is ageing. As a result, shipbuilders expect a further surge in LPG carrier construction contract awards as the older vessels will soon require replacing as LPG carrier owners begin to modernise their fleets.

According to UK shipping information specialist Clarkson, some 68 LPG and LPG/ammonia carriers in operation worldwide are more than 20 years old. A further 15 LPG tankers are between 15 to 19 years old, while 40 carriers are aged from 10 to 14 years old.

Among the world's large LPG carrier fleet operators, Bergesen of Norway owns about 50 LPG and LPG/ammonia tankers. Its LPG and LPG/ammonia carrier fleet includes 20 vessels of 60,000–99,000 cm capacity and another 20 vessels of 20,000–60,000 cm in size. Naftomar is another important LPG/ammonia carrier fleet owner. The company owns 28 vessels, of which 13 are more than 20,000 cm in capacity.

## LPG newbuild market

'We foresee a slight improvement in the world LPG carrier market,' commented a source at Daewoo Shipbuilding & Marine Engineering Co Ltd (DSME) of South Korea. 'One of the reasons is that due to Asian countries' growing economies they need more LPG and natural gas. LPG demand in China will improve. China imported 14mn tonnes of LPG in 2002 and will reach 18mn tonnes by 2005. They are importing mainly from the Arabian Gulf area. Another factor is that many LPG and LPG/ammonia carriers will need to be replaced as they were built at the end of the 1970s.'

DSME is one of three South Korean shipbuilders looking to increase their share of the global LPG carrier shipbuilding business. Hyundai Heavy Industries and STX also build LPG carriers, while in Japan competing shipyards include Kawasaki Shipbuilding, Mitsubishi Heavy Industries and Universal Shipyard (formerly Hitachi/Mitsui). Elsewhere, in Europe, shipbuilders supplying LPG tankers include Fincantieri of Italy and a number of Polish shipyards.

Since the early 1980s Daewoo has developed an international reputation as a shipbuilder and specialist in the offshore construction industry. Apart from building oil tankers and LNG tankers, DSME has a long track record building bulk carriers, containerships and other vessels. The company now is looking to expand its LPG tanker shipbuilding business after signing contracts to build five medium-size LPG/ammonia tankers in 2003.

Daewoo first began to build gas and chemical tankers about 20 years ago, but has since stopped building smaller size chemical tankers. 'In the mid-1980s we built several methanol tankers but not recently as we have very few inquiries,' the source explained. 'Methanol and chemical tankers are quite similar, but are different to LPG carriers. We are not interested in chemical tankers now as they are relatively small, at about 20,000 to 40,000 dwt, and very complex. We prefer 40,000 dwt tankers and larger. However, for oil tankers we are focusing on VLCC tankers of 300,000 dwt and upwards. For LPG gas carriers we design 38,000 cm tankers, which is the medium size for LPG and LPG/ammonia tankers.'

## Growing business

Since the late 1990s Daewoo has won a series of gas carrier contracts, particularly for LNG carriers. At the end of 2003 DSME is believed to have delivered seven LNG tankers and had a further 18 LNG tankers either under construction or on order.

Orders for LPG and LPG/ammonia carriers also have begun to grow recently. At the end of 2003 DSME is believed to have delivered two LPG/ammonia carriers and had a further six LPG and LPG/ammonia tankers either under construction or on order.

A typical fully-refrigerated LPG tanker is designed to carry various cargoes, including propane, butane, anhydrous ammonia, butylenes, propylene, butadiene and vinyl chloride monomer (VCM). Because LPG carriers generally have three independent, self-supporting prismatic cargo tanks, each tanker can carry three separate cargoes for different customers. The actual gases carried onboard each vessel may change frequently depending on each shipper's needs.

'Ammonia is carried in LPG ships designed for propane and butane. There is no dedicated ammonia carrier,' the source explained. 'The main difference between LPG and ammonia is the specific gravity. It is common to carry different cargoes on the same vessel. The ship owner needs a small deck tank to assist with the ammonia loading.'

A standard 38,500 cm LPG carrier has three gas tanks, each being a different size due to the shape and size of the ship's hull. Normally the number one tank is designed to hold 11,000 cm, the second tank 15,000 cm and the third tank 12,000 cm. 'The design of an LPG carrier is quite standardised. The main development in ship design is the hull shape,' the source said. 'The pumping system depends on the pump manufacturer. There have been no recent changes in the tank design for 38,500 cm vessels, but different design specifications are used for different size vessels.'

The majority of LPG carriers in service around the world are 30,000–50,000 cm in capacity. Most of the LNG tankers that DSME builds are 138,000–145,000 cm in capacity. LNG tankers of 75,000 cm are considered medium size. In contrast, LPG carriers below 20,000 cm capacity are regarded as small, 30,000–50,000 cm vessels are medium size. Large LPG tankers are those over 70,000 cm.

'Large LPG vessels mostly carry pure LPG, but medium LPG carriers are more flexible in their loading and can carry different LPG types, including ammonia and vinyl chloride monomer (VCM),' the source commented. 'It is a tradition that medium and smaller LPG vessels have smaller deck tanks, usually two per vessel, to help with cargo exchange. But large LPG carriers do not have a deck tank, and without a deck tank it is difficult to carry different gases.'

VCM, for example, has a specific gravity of 0.97, which is much heavier than normal LPG. Consequently VCM is usually carried in medium or smaller vessels because if it were carried in a large vessel, both the ship's tanks and structure would need to be reinforced to cope with the high specific gravity, which would involve a higher construction price.

## Daewoo order book

Daewoo's Okpo shipyard is located on Koje Island, which lies 40 km southwest of Pusan, off the southeastern tip of the Korean peninsular. Facilities include two dry docks for building new vessels and three floating docks, mainly for repair work, but which can also be used to build new ships. DSME employs 11,000 staff, including 1,400 engineers and 6,200 skilled workers. In addition the company uses a number of subcontractors who, in turn, employ about 6,000 workers.

Daewoo's LPG carrier order book currently consists of one large LPG carrier and five medium-size LPG/ammonia carriers. A large 78,000 cm capacity LPG carrier is being built for a Swiss owner, while five 38,500 cm LPG/ammonia carriers have been ordered by three European owners.

In April 2003, Bergesen of Norway awarded DSME an order for two 38,500 cm, fully-refrigerated LPG/ammonia carriers. The same day contracts were also signed with AP Moller of Denmark for two 38,500 cm capacity LPG/ammonia carriers and Exmar of Belgium for one 38,500 cm capacity LPG/ammonia vessel.

'LPG/ammonia carrier contracts are not always awarded by international tender. Some are invited tenders,' the DSME source noted. 'Bergesen, AP Moller and Exmar joined together to offer five vessels to get a cheaper price than by tendering their individual contracts alone. It is not so common to do this. We got the contract on April 25, 2003.' Two other shipbuilders also bid for the contracts – Hyundai of South Korea and Mitsubishi of Japan. The contract price is believed to be about $41.4mn for each vessel.

Bergesen also has various other LPG carriers on order. Kawasaki Shipbuilding of Japan recently delivered a newly built LPG tanker to Bergesen and has orders in hand to build four more carriers for the Norwegian client.

## Rising prices

LPG tanker prices are starting to rise as shipyards report a strong upturn in orders. In 2003, South Korean shipbuilders recorded their biggest orders in the country's history. Hyundai Heavy Industries, the world's largest shipbuilder, booking orders worth $6.8bn in 2003. Samsung Heavy Industries replaced Daewoo as the world's second largest shipbuilder in 2003, booking orders worth more than $6bn, while DSME won new shipbuilding business worth about $3.2bn.

Buoyant ship orders have continued into 2004, with shipbuilders reporting first quarter orders worth 29% more than the same period last year. Foreign orders for 11 LNG tankers were placed with shipyards between January and May, contributing to the strong first half performance. Most South Korean shipyards are believed to have sufficient orders in hand to keep them busy for the next three years.

'Gas carrier prices are starting to go up slightly,' the source commented. 'We are escaping from the bottom. Now is still a good time for gas carrier and oil tanker owners to buy, but there is limited berth space available in shipyards so ship prices are going up. Many types of ships are being built. Most South Korean shipyards are nearly full, so ship owners will have to wait some years.'

Building a 38,500 cm LPG carrier normally takes 20 to 22 months. DSME has contracted to deliver the first of the five LPG/ammonia carriers in November 2005 and will deliver the four other vessels at three-monthly intervals thereafter. Bergesen will take delivery of the first vessel, AP Moller has agreed to take the second LPG/ammonia carrier and Exmar the third. AP Moller will also take delivery of the fourth vessel, while the last carrier to be completed will be for Bergesen.

## Tough competition

Meanwhile, competition among shipyards for orders remains tough and shipbuilders are constantly looking for ways to reduce construction costs. 'We compete with efficient ship design and shipbuilding. We use robots for welding to improve our production efficiency,' the source said. 'The five LPG/ammonia carriers are 99.5% the same design. The 0.5% difference is that some ship owners require a thruster in front of the vessel to improve manoeuvrability.'

However, while the DSME source was confident that there would be 'a slight increase in world orders for LPG carriers as replacement begins', he did signal a cautionary note, stating that competition for business could also grow if Chinese shipyards entered the business as well.

# Monitoring natural attenuation of groundwater contamination

**The Soil, Waste and Groundwater Working Group of the Energy Institute (EI) has joined forces with the Environment Agency (EA) to commission Land Quality Management at the University of Nottingham to produce a package of training materials for the implementation of monitored natural attenuation (MNA) of chemical contamination of groundwater. *Gordon Lethbridge*, HSE Consultancy Group, Shell Global Solutions, reports.**

Plumes of dissolved phase contamination in groundwater are frequently much shorter than expected based on the rate of groundwater flow. This is because they undergo natural attenuation by a variety of mechanisms based on the following processes:

- biological (eg biodegradation),
- physical (eg dilution by diffusion and dispersion, retardation by sorption onto aquifer sediments and volatilisation), and
- chemical (eg degradation by mechanisms such as hydrolysis).

As far as petroleum hydrocarbon contamination is concerned, biodegradation is by far the most important natural attenuation mechanism for those components of petroleum products which have sufficient solubility in water to form dissolved phase plumes of significance, such as benzene, toluene, ethylbenzene and xylenes (BTEX), and naphthalene. Naturally occurring hydrocarbon micro-organisms in aquifers use these petroleum components as a source of food, breaking them down in the process to the harmless products carbon dioxide and water, thereby reducing the spreading of the contamination in the groundwater. These microbes are very widespread in nature. It is very rare for them not to be present in the soil and groundwater at a petroleum-contaminated site.

## Life cycle

A plume of BTEX in groundwater at a petroleum-contaminated site typically goes through a four-stage life-cycle (see Table 1 and Figure 1). Depending on the size of the source, a plume can remain in steady state for decades. However, once a plume has started to recede, it can typically disappear in one to two years.

Studies on the dimensions of over 1,000 BTEX plumes in groundwater in a variety of hydrogeological conditions have demonstrated that the majority of dissolved phase plumes extend less than 100 metres from the edge of the source.

## Managing the risks

It is now generally accepted by experts that natural attenuation processes can play a major role in managing the risks arising from groundwater contamination in preventing a groundwater contamination plume from reaching a sensitive receptor – such as a drinking water supply well or a surface water body such as a river or lake – thereby obviating the need for expensive engineered remedial solutions. Indeed, in complex hydrogeology typical of the UK (eg dual porosity aquifers and heterogeneous made ground) MNA may be the only cost-effective solution, given that:

- *Ex situ* groundwater remediation using pump and treat systems will have to operate for decades, if not centuries, due to limitations arising from sorption-desorption equilibria of hydrophobic chemicals in aquifer systems.
- *In situ* groundwater remediation involving aggressive treatment of the whole plume is unlikely to be feasible due to the technical challenges in uniformly delivering treatments (eg air, nitrate) throughout the plume due to preferential flow paths arising from heterogeneity in the aquifer.
- Permeable reactive barriers which show great promise in treating the advancing edge of the plume are limited to relatively shallow applications in relatively simple formations whose behaviour can be modelled and predicted.

Natural attenuation of contaminants is not restricted to groundwater plumes, although this is where most of the work has been done and our understanding is the greatest. It can also be important for limiting the vertical migration of contaminants being leached out of sources and for limiting the transport of vapours of volatile contaminants as they diffuse through the soil both vertically and horizontally. Finally, residual phase (immobile) sources can also be subject to natural attenuation processes.

| Stage | Name | Description |
|---|---|---|
| 1 | Expansion | The plume grows in size because the rate at which BTEX leaches out of the source exceeds the biodegradation capacity of the aquifer. |
| 2 | Steady state | The plume ceases to expand and stabilises as the biodegradation capacity of the aquifer matches the rate at which BTEX leaches out of the source. |
| 3 | Collapse | The plume starts to recede back towards the source as the BTEX content of the source declines such that the rate of biodegradation exceeds the leaching rate. |
| 4 | Exhaustion | All the BTEX has been leached out of the source and the plume eventually disappears. |

Table 1. The life-cycle of a dissolved phase BTEX plume in groundwater

## Monitoring data

MNA is not a 'do nothing' solution. The challenge is to gain the necessary monitoring data to provide confidence to all stakeholders that natural attenuation of the contamination is taking place at a sufficient rate to ensure that the plume will not impact any sensitive receptors in the vicinity of the site in either the short or long term. This requires a detailed understanding of contamination sources, their behaviour (eg fate and transport) in the subsurface and the pathways by which receptors in the vicinity of the site might be impacted.

Consequently, the costs of site investigation and monitoring for MNA will be greater than those incurred for site investigation and monitoring for a typical ex situ remediation project (eg dig and dump, and pump and treat), since the level of knowledge and technical understanding required to satisfactorily achieve the latter is less than for the former. However, the increased site investigation and monitoring costs for MNA will be compensated many times over in the savings resulting from not having to apply costly engineering solutions to manage the risk arising from the groundwater contamination plume in the remediation phase. So, overall, total risk management costs will be reduced significantly.

If we are to fully exploit the tremendous potential of MNA for managing the risks arising from soil and groundwater contamination, it is vital that all stakeholders (site owners, regulators, developers, financiers, consultants and local residents) have a good understanding of the subject to promote confidence in its application at a particular site. Some degree of natural attenuation takes place at all contaminated sites; the key question is: 'Will the rate be sufficient to protect receptors now and in the future?' Stakeholders need confidence in the measurements of efficacy at a particular site, and the predictability and durability of natural attenuation processes gained from modelling.

## Training package

The EA-EI training package is designed to facilitate the learning process and the development of confidence in MNA based solutions. It can be used for personal tuition by distance learning or group learning led by a trainer. It contains the following material:

- Slide pack
- Trainers notes to underpin the slides
- Questions for self-assessment
- An exercise based on a real site
- Case studies of MNA (new case studies will be added as they are made available)

The exercise is essentially a computer 'game' in which the object is to build a technically defensible case for risk management of groundwater contamination by MNA at lowest cost. It can be 'played' by individuals or teams competing against each other. The software contains a large amount of data about the site. The 'player(s)' have to decide on their site investigation strategy, where to take soil and groundwater samples and what to analyse them for, and where to install groundwater quality monitoring wells and the extent of monitoring required. The software provides the data that is 'bought'. The player(s) then have to interpret the data they receive and determine their next course of action, until they are confident they have a technically defensible case to support the application of MNA at the site. (See **Figures 2** and **3**.)

The training materials are web-based and located on a server at the University of Nottingham (**www.howtomna.com**).

For more information, contact Martin Maeso, Technical Team Manager, at the Energy Institute on t: +44 (0)20 7467 7128, e:**mmaeso@energyinst.org.uk**


Figure 1: The four-stage life-cycle of a dissolved phase BTEX plume in groundwater

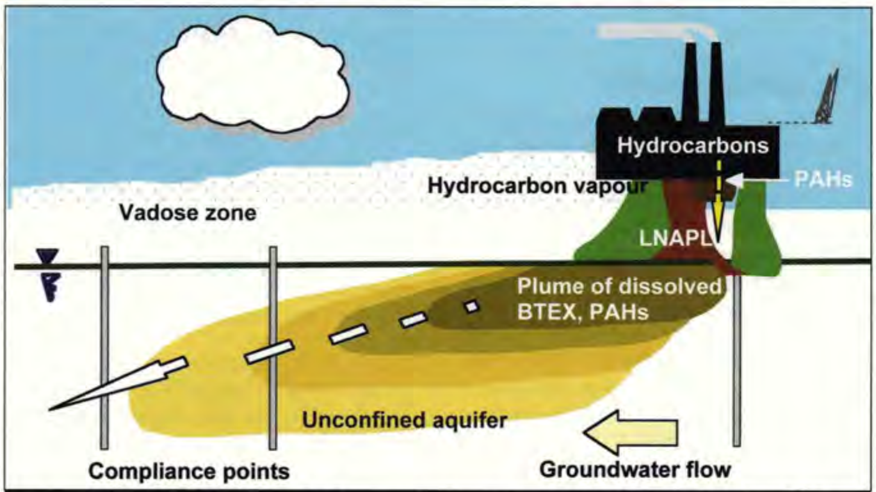




Figure 2: Screen shot from the EA-EI computer 'game' training package – Hazard and risk assessment of contaminated land, an example conceptual model

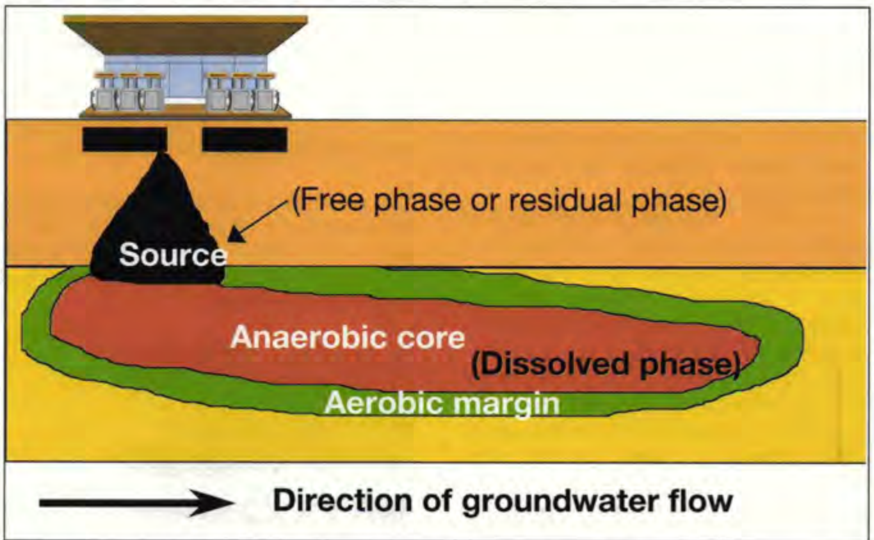




Figure 3: Screen shot – Conceptual model of hydrocarbon plume in groundwater

...continued from p43

## Peak production

For global oil production to move into decline – in other words to 'peak' – all that is required is for the volume lost in the declining countries to exceed the gains made in countries where production is still expanding. As the figures show it will be some time before this occurs.

In 2003 decline was running at a little over 1mn b/d and production gains at just under 4mn b/d. Last year can, however, be regarded as exceptional, with notably large output increases (over 10%) seen from a number of major producers – Iran, UAE, Qatar, Kuwait, Saudi Arabia, Algeria and Russia. It seems unlikely that such large increases can be repeated or sustained without massive new investment.

## Production gains

Over the last two years no less than 15 countries have recorded production increases of over 5%/y; eight of these have sustained gains of over 10%/y. Amongst this group, where production is expanding fastest, the most important is undoubtedly Russia, where production has expanded rapidly since 1999 and is set to top 9mn b/d this year (2004). The other large sustained expanders are Brazil, Algeria, Angola and Kazakhstan. Sudan and Equatorial Guinea have been growing notably fast, but from low bases, and have not yet attained the status of major producers.

Five Middle East producers expanded very fast in 2003. This, however, came after an extended period in which their production levels were little changed. With little or no spare capacity now available around the world, production expansion will be closely linked to new project start-ups. (See table of megaprojects, pXX.)

Analysis of this year's oil production statistics leads to the conclusion that declining production and depletion is now a significant influence and that rapid production increases are sustainable in only a limited number of countries. This, in turn, gives a very great deal of political and financial leverage to those countries that do have expansion potential. As **Table 1** shows, total North American production peaked in 1997 while Asia-Pacific production peaked in 2000 and OECD production in 1998. Latin American production may have peaked in 2002, although it is too early to be sure.

What this year's BP statistics confirm is that, if the world is to get the oil production it is likely to require, a great deal of additional investment will have to take place.



**Winding up of the IP**

As you may be aware, following the merger of the IP with the InstE and as agreed by members at the EGM held on 5th March 2003, the Energy Institute will be applying to the Registrar of Companies under section 652a of the Companies Act 1985 for the Institute of Petroleum to be wound up and struck off the Register. Companies House Form 652a will, accordingly, be completed and returned.

# EI Autumn Luncheon

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

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

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

*This well established date in the energy calendar of events provides a unique opportunity to hear an internationally renowned figure speak on contemporary global issues effecting our industry.*

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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The Energy Institute (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 ☐

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