SEPTEMBER 2005

Petroleum review

NORTH SEA

- Struggling to slow North Sea depletion
- Taxation on a declining province

GAS MEGAPROJECTS

- LNG boom continues apace

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- No compromise on safety

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Petroleum review

SEPTEMBER 2005 VOLUME 59 NUMBER 704
SINGLE ISSUE £15.00 SUBSCRIPTIONS (INLAND) £215.00
AIRMAIL £358.00

PUBLISHER

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ABC Printed by Thanet Press Ltd, Margate

MEMBER OF THE AUDIT BUREAU OF CIRCULATION

ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

No single letter abbreviations are used.
Abbreviations go together eg. 100mn cf/y = 100 million cubic feet per year.

Front cover picture: Statfjord's reservoir will soon be depressurised and platforms modified to convert the field to gas production (see p17)
Photo: Øyvind Hagen/Statoil

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The Energy Institute as a body is not responsible either for the statements made or opinions expressed in these pages. Those readers wishing to attend future events advertised are advised to check with the contacts in the organisation listed closer to the date, in case of late changes or cancellations.

FROM THE EDITOR

Now the market rules

The death of Opec has been predicted so many times that to do so again would be folly. The wry observation that the oil cartel is like a teabag – it only works when it is in hot water – is probably nearer the mark. However, with no real spare capacity and member Indonesia now an oil importer, Opec is, for the moment, without market power.

In 1970 the Texas Railroad Commission (TRC) set production allowables at 100% for the first time and the era of controlling oil prices by controlling Texan production drew to a close. [In 1970 Texas was what Saudi Arabia was in the 1990s – it had enough spare capacity to depress prices when released on to the market. The TRC set allowable production levels for all Texan fields each month, to manage prices at an 'acceptable' level.] In fact, from 1971 onwards, US lower 48 production moved into slow, steady, inexorable decline.

This month's (August) *Oil Market Report* from the International Energy Agency (IEA) records – on p15 – that: 'Total supply from the Opec-10 (ie excluding Iraq) averaged 27.7mn b/d versus a 28mn b/d quota target effective from 1 July. It may be a trivial point or a straw in the wind. Opec, to this columnist's recollection, has never before underperformed a target quota – it usually struggles with 'quota cheating' to get production down to the target.

Further straws in the wind are that the retiring Energy Minister in Iran has indicated that capacity loss from producing fields are now running at 300,000 to 400,000 b/d, or around 6% to 10%, each year. Taken literally, this means Iran will lose 1.75mn b/d of capacity by the end of the decade. The challenge of developing the replacement capacity in the period will be an enormous one.

In the July, August and September 2004 issues of the *Oil Market Report* (accessible free at **www.iea.org**) the IEA attempted to gauge future Opec capacity. While its conclusions were relatively optimistic, the key and unknown variable is the level of capacity erosion in existing fields. If Iran is any guide, these may already be quite high.

For the moment – and that moment may be quite long – there is effectively no spare capacity in the world. (Is effectively unsaleable heavy sour crude out of Saudi Arabia really spare capacity?) This means that the market now rules. No country or company in any conceivable form can now moderate prices, although removal of capacity would obviously spike prices. In such a situation, rumour, speculation and market manoeuvering promise a bumpy ride. Goldman Sachs, in its latest assessment in a just issued report, predicts that WTI prices will remain above \$60/b for the remainder of the decade. This follows its prediction earlier in the year that oil markets had entered a period in which super spikes could hike oil prices to \$105/b.

Predicting future oil prices is a game for the brave and the foolhardy. The real question is at what point does the economic drag of high oil prices cause economic growth to slow, or even stop?

So far, the world has been quite extraordinarily lucky. A series of generally mild winters has allowed North America to get by with a restricted gas supply that could easily have caused crisis. Oil supply has, so far, remained virtually uninterrupted. This year, until the Thunder Horse semi-submersible accident, virtually all new projects had flowed on time – with Kizomba B even early. The effective loss of a Bombay High platform following a fire reminds us that, in a large and complex system, accidents and capacity loss do occur. The US refining industry has just been through this. After a long period of high capacity operation, a series of accidents and unit problems led to shutdowns and capacity restrictions. This, in turn, spooked the markets and drove WTI prices to \$67/b. As units came back onstream, prices eased back to \$63/b. Clearly, market perceptions now rule and price instability is the order of the day.

The latest update of LNG projects (see p22) clearly shows the industry's massive commitment to monetising remote gas reserves. It also clearly shows the way that reductions in LNG production costs have opened up the market, providing the world with a competitively priced fuel in substantial volumes.

In contrast, our latest round-up of North Sea prospects and projects (p12 shows the struggle to slow production decline in the face of few large undeveloped reserves but many small accumulations to be developed while the major infrastructure is still in place.

We are very pleased to include with this issue of *Petroleum Review*, the first edition of our *Future Fuels Supplement*. Rapid progress is now being made in commercialising biodiesel and bioethanol as alternative fuels or fuel extenders. The supplement clearly shows just how much progress has already been made.

Chris Skrebowski

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

E-DATA

Inverurie-based DeltaStudios and Aberdeen-based Logical Advantage have developed an Internet-accessed service – DeltaChemicals™ – that is designed to collate the usage of production chemicals offshore and produce the required Environmental Emissions Monitoring System (EEMS) report in accordance with DTI requirements.

ABS has set up a new section on its website providing a range of technical information on LNG shipping and terminals. A range of free downloads provide guidance on offshore LNG terminals, membrane LNG tanker design, dual-fuel propulsion, and other topics. The information can be found at **www.eagle.org/prodserv/offshore/gasmarkets/index.html**

Petroleum processors seeking to maximise production and minimise spoilage can now access a free-of-charge 'Temperature and Temperature/Humidity Mapping Guide' from Dickson Company at **www.dicksonweb.com/article/article_26.php** This best practices guide to warehouse and production facility temperature and humidity mapping can potentially save users thousands of dollars annually by protecting inventory quality, claims the company.

UK offshore safety statistics for 2004/2005 show a reduction in the rate of fatal and major injuries to workers, with the number of work-related deaths standing at zero, compared to three in 2003/2004. The provisional statistics, which also reveal that there were 48 major injuries during the period, are contained within the *Offshore Safety Statistics Bulletin 2004/05*, published by the Health and Safety Executive (HSE) at **www.hse.gov.uk/offshore/statistics/stat0405.htm**

Tough new measures to reduce environmental pollutants will come into effect in the UK on 1 July 2006 through the Restriction of Hazardous Substances (EU Directive RoHS 2002/95/EC). To assist manufacturers, suppliers and recyclers who must screen or verification test materials and components to ensure product compliance, Oxford Instruments has developed an online RoHS by XRF information resource that can be viewed at **www.rohsbyxrf.com**

Gemini Data Loggers new website at **www.geminidataloggers.com** features a new **www.tinytag.info** product section designed for ease of access to key information about the company's range of Tinytag battery-operated data loggers.

Scana UK has now made available the video demonstration and animation of its patented Truload system on its website at **www.scanauk.com** The Truload system is claimed to offer an easy, cost efficient method of ensuring the integrity of industrial fasteners throughout their working lifetime.

UK

ATP Oil & Gas has been given the *green light for development of the Tors fields (Garrow and Kilmar) in the southern gas basin of the UK North Sea. First production at Kilmar is expected early in 2006, followed later in the year by Garrow.*

Rig utilisation in the North Sea main- *tained its multi-year peak of 91.8% in July, unchanged from June, according to Platts* North Sea Letter. *With four rigs cold-stacked, utilisation is effectively 100% and remains equally strong going forward. Utilisation six-months forward is above 90%, while even 12-months forward it is 83.9%, up 1.2% from June.*

Venture Production is to acquire for *£575,000 from Esso Exploration and Production a 50% stake in North Sea block 21/20b, containing part of the Christian oil discovery, and a 12.88% interest in block 21/20a (excluding the Cook field area), which contains the remainder of Christian and the entirety of the Bligh gas condensate discovery.*

EUROPE

An agreement to sell a 20% holding in *production licence (PL) 251 in the Møre basin area of the Norwegian Sea has been concluded by Statoil with UK-owned gas company BG Norge. The farm-out will leave the group with 70% of the deepwater licence. Shell holds the remaining 10%.*

An oil discovery has been made by *Statoil in the M5 structure in the Tampen area of the North Sea, which will be produced via the Vigdis field just to the north.*

Island Oil and Gas has been granted a *100% interest in frontier exploration licence 05/3 covering blocks 18/10, 19/1 and 19/6 in the north-east Rockall basin off the west coast of Ireland.*

EASTERN EUROPE

Bulgaria's Oil and Gas Exploration *Company has been granted a permit to prospect for oil and gas in the Shabla block in the northern part of the Bulgarian Black Sea shelf, writes* Stella Zenkovich. *Meanwhile, Russia's Bashkirgeologia has been issued a permit to prospect for hydrocarbons in the Yambol block, located in the Sliven, Haskovo, Yambol and Bourgas regions.*

Kizomba B onstream early

ExxonMobil has started production of the $3.5bn Kizomba B project offshore Angola, which will produce 1bn barrels of oil from the Kissanje and Dikanza fields. The project – which includes what is claimed to be the world's largest FPSO (floating production, storage and offloading vessel), with a storage capacity of 2.2mn oil barrels – has come onstream more than five months ahead of schedule.

To accomplish this milestone, ExxonMobil incorporated its unique 'design one, build multiple' approach that captured learnings and synergies from the Kizomba A project, a virtually identical development that began production on block 15 (Hungo and Chocalho fields) less than one year ago.

With combined estimated recoverable resources of 2bn barrels of oil, Kizomba A and Kizomba B, along with the Xikomba project that began producing in 2003, are expected to reach a peak output of more than 550,000 b/d by year-end.

In addition to ExxonMobil (operator, 40%), other participants in block 15 are BP (26.67%), Eni (20%) and Statoil (13.33%). Sonangol is the concessionaire.

New digital maps of UK territorial waters

SeaZone Solutions is soon to release its most detailed and comprehensive maps ever produced of the UK's territorial waters. The new digital mapping will contain information never before included on nautical charts – from a complete wrecks database to detailed information on conservation zones, the sea bed and much more.

'The definitive geographical information within SeaZone Hydrospatial will improve the quality of decision-making and its importance to marine and coastal management projects cannot be underestimated,' states the company. 'For the first time, project managers and GIS operators have a complete and authoritative dataset of UK waters at their disposal.' In a further major innovation SeaZone Hydrospatial is extending the UK's Digital National Framework offshore, providing a geographic information base interoperable with Ordnance Survey's OS MasterMap® for the marine environment and coastal zone.

'Using SeaZone Hydrospatial will reduce project set up and running costs, improve project delivery times and results accuracy. It will allow, for the first time, projects working along the coast to model both onshore and offshore environments,' states SeaZone.

The comprehensive dataset, at two scales 1:25 000 and 1:250 000, covers the UK's entire territorial waters. The data is available in six data rich and cohesive layers – Bathymetry & Elevation, Natural & Physical Environment, Structures & Obstructions, Socio-economic & Marine Use, Conservation & Environment, Climate & Oceanography – which reduces data volumes and allows the purchase of interest specific data tailored to the customer's needs.

Enhanced seismic now available for Danish licensing round

Ødegaard, an international provider of technology to the oil industry, is playing a key role in offering specially enhanced seismic data to E&P companies considering applications for exploration acreage in Denmark's 6th Offshore Licensing Round, which closes on 1 November this year.

In collaboration with TGS-Nopec and Fugro-Geoteam, Ødegaard has applied acoustic impedance inversion to an extensive non-exclusive seismic database prepared for the Danish licensing round launched in May 2005. Ødegaard's inversion technique has tied well log data from 61 wells to the relevant seismic horizons and seismic velocities. Central to the process has been the use of the company's ISIS globally optimised inversion algorithm. The net result is claimed to have dramatically improved previously available data for modelling the subsurface, enabling companies to derive a crucial rock properties prediction and hence a better idea of oil and gas potential in the blocks on offer.

The inversion initiative is reported to be the kind of new technology application that the Danish Energy Authority is hoping will breathe new life into the country's offshore oil and gas activity after 30 years of operation. The 6th round focuses on the Central Graben and some known oilfield areas to the east, a large portion of which has not been drilled and is dependent on quality seismic data for hydrocarbon prospect evaluation.

NORTH AMERICA

The US Minerals Management Service *(MMS) has awarded Shell Offshore a total of 84 leases in the Beaufort Sea, offshore Alaska. Shell bid on the leases in the March 2005 Outer Continental Shelf Lease Sale 195.*

MIDDLE EAST

The first phase of development of the *Darkhovin oil field in Iran has been officially inaugurated, with current production standing at 55,000 b/d, reports* Stella Zenkovich. *The second phase, which will increase daily output to 160,000 b/d will be finished next year. Eni operates the project with a 60% working interest on behalf of the National Iranian Oil Company. Eni's Iranian partner is Naftiran Intertrade Company (NICO), which holds a 40% share.*

Lukoil (25%) reports that oil has been *discovered at the Anaran block in western Iran, which is operated by Norsk Hydro (75%).*

The Abu Dhabi National Oil Company *(Adnoc) is planning to increase production of gas liquids by more than 50% over the next five years in order to meet growing market demand, reports* Stella Zenkovich. *Adnoc's current production of natural gas, LNG and gas liquids and condensates is equivalent to 1.2mn boe/d – roughly half the current crude production of the United Arab Emirates.*

RUSSIA/CENTRAL ASIA

Sibneft has formed a new subsidiary to *manage oil and gas projects in Russia's Omsk and Tomsk regions.*

ASIA-PACIFIC

Chinese demand for crude oil is fore- *cast to rise about 6% from last year to 6.2mn b/d in 2005, according to a new government survey, it has been reported. Domestic crude production is predicted to rise by just 3%, to 3.6mn b/d, leaving a shortfall of 2.6mn b/d and implying a 6% increase from last year's average crude oil imports of 2.45mn b/d. China's crude imports rose 35% in 2004, helping to push prices above $50/b for the first time.*

Indonesia has announced the tender *winners for nine oil and gas blocks.*

Transneft comes to Lake Baikal

The Federal Nature Management Oversight Service (FNMOS) and Greenpeace Russia have accused oil giant Transneft of conducting a secret survey around Lake Baikal under its East Siberia-Pacific project, reports *Tatyana Sinitsyna* of RIA Novosti. Both organizations claim that the oil company has illegally begun preparations for laying a pipeline along the northern edge of what is the world's largest freshwater lake.

Transneft was given government approval for its project in November last year after extensive legal wrangling. However, according to FNMOS Deputy Head Oleg Mitvol, only one document entitled 'Grounds for Investing in the Construction of an East Siberia-Pacific Oil-Pipeline System' was approved and no state environmental expertise was carried out. Shortly afterwards, Transneft is understood to have rejected its original planned route, which ran at least 140 km from Baikal, due to poor terrain, instead choosing another route much closer to the lake. It is claimed to be far easier and less expensive to lay the pipeline close to Baikal than in the forest, or to have to dig through the hills in the approved area.

It is hoped that the 4,000-km pipeline will help stimulate economic development in the region. The Japan Bank for International Cooperation has promised $12bn of funding, while China, South Korea, India and other countries are in negotiations.

Mukhaizna project

Occidental Petroleum is understood to have been given the green light for further development of the Mukhaizna field, one of the largest oil fields in Oman. Occidental will act as operator of the field, holding a 45% stake. The Omani government will hold a 20% interest through Oman Oil Company, with a further 17% held by Shell Oman, 15% by Liwa Energy (an investment company of the government of Abu Dhabi), 2% by Total E&P Oman and 1% held by Partex (Oman).

Mukhaizna is currently producing some 10,000 b/d of oil. Occidental and its partners plan to invest over $2bn to implement a large-scale steam flood to increase production to approximately 150,000 b/d within the next few years and to recover approximately 1bn barrels of oil over the life of the project.

Statoil contract awards

Contracts worth a total of NKr590m have recently been awarded by Statoil for its Skinfaks development and Rimfaks expansion project in the Norwegian North Sea. Subsea 7 will lay pipelines to tie the new subsea installations back to the group's nearby Gullfaks C platform under a contract worth just under NKr190mn. Saipem has been given the job of carrying out all subsea connection work, valued at roughly NKr230mn. Modifications on Gullfaks will be undertaken by Fabricom at a cost of NKr170mn.

Production is due to start in November 2006. Recoverable reserves are estimated to be about 70mn boe. Statoil has a 61% interest in the development. Partners are Petoro (30%) and Norsk Hydro (9%).

Call for US/West Africa alliance

As gas prices continue to skyrocket, the debate over how to address America's energy crisis has intensified among policymakers, analysts and other key opinion leaders. Simultaneously, the US faces increased international pressure to provide more aid, fair trade and debt relief assistance to sub-Saharan African countries.

A new study by the Congressional Black Caucus Foundation (CBCF) – entitled *Breaking the Oil Syndrome: Responsible Hydrocarbon Development in West Africa* – argues that the US must link these seemingly disparate concerns by forming a strategic alliance with West African hydrocarbon states that can help secure US energy needs while advancing human and infrastructure development goals in West Africa.

'The fact of the matter is that West Africa is vital to the energy security of the United States,' said Dr Don Tharpe, President and CEO of CBCF. 'The region is poised to increase the world supply of oil but it has been largely overlooked as a key US partner in this regard.'

The paper highlights that a mutually beneficial dynamic engagement framework will be especially important as the demand and competition for scarce oil resources increases in countries like China and India.

These included ConocoPhillips, who secured the right to explore the Amborip VI block in the Arafura Sea, while local company PT Energi Timur Jauh, a subsidiary of the second largest local oil company PT Energi Mega Persada, got the East Kangean block in East Java. A total of 13 blocks were offered, but only 11 attracted 23 bids from 21 companies. In order to attract more investors, the Indonesian government is reported to have scrapped value-added taxes and import duties for all capital goods during exploration and production periods. It has also lowered its share of the oil output to between 65% and 80%, down from around 85% applied in previous contracts.

Brunei Shell Petroleum is reported to *have discovered oil in Brunei for the second time in 11 months, in the Seria North Flank area. Discovered in 1929, the Seria field accounts for over 90% of Brunei oil production. Oil production peaked at more than 240,000 b/d in 1979, but has now fallen to below 220,000 b/d as the country has cut output to extend the life of its oil fields and improve recovery rates. Brunei's crude reserves are currently put at 1.1bn barrels.*

Talisman Energy has announced first *oil production from the South Angsi field in block PM-305 offshore Malaysia, just 18 months after the field development plan was approved. In addition, a recent seismic survey has identified further exploration potential close to the South Angsi field, in block PM-314, and the company plans to drill a prospect later this year. South Angsi is expected to produce at a plateau rate of approximately 12,000 b/d (net Talisman share).*

Reliance Industries is reported to have *found 3.76tn cf of in-place gas reserves in two coal bed methane (CBM) blocks in the Sohagpur East and Sohagpur West blocks in India.*

Eni has won the rights to explore *blocks 8 and D6 offshore India, following an international bid tender. This is the first exploration contract awarded to Eni in the country.*

Apache's Mohave-1H discovery in the *Carnarvon basin offshore Western Australia has come onstream at a rate of 10,690 b/d of oil. The field is part of the Harriet joint venture, which Apache operates with a 68.5% interest.*

Anadarko Petroleum has significantly *increased its access to exploration acreage in Indonesia through an*

UK oil output decline continues

UK combined oil and gas production in May remained static for the first time in a year, according to the latest (August) Royal Bank of Scotland Oil and Gas Index. This was largely driven by some growth in gas production, up 3.5% on the year at 9,549mn cf/d, and a small year-on-year decline in oil production of 3%, down to 1,724,597 b/d.

Tony Wood, Senior Economist with The Royal Bank of Scotland Group said: 'May's data represents a significant turnaround in UK oil and gas production, which has seen continual declines during the past two years. While it is important not to read too much into one month's data, it can be expected that the current positive environment in the North Sea will see some turnaround in the rate of production decline over the coming months.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
May 2004	1,778,979	9,218	37.72
Jun	1,776,246	10,192	35.21
Jul	1,758,312	10,292	38.15
Aug	1,621,582	8,585	42.99
Sep	1,526,692	8,716	42.92
Oct	1,630,230	9,677	49.66
Nov	1,748,744	10,385	42.88
Dec	1,800,309	10,823	39.55
Jan 2005	1,725,929	10,444	44.24
Feb	1,742,295	9,759	45.50
Mar	1,703,744	10,514	52.95
Apr	1,749,773	10,290	51.83
May	1,724,597	9,549	52.95

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Japan and China in territorial dispute

The Japanese government is reported to have granted Teikoku Oil concessions to undertake exploration drilling in the East China Sea, close to gas fields currently being explored by a Chinese consortium. The go-ahead was given after approval was given by the governors of south Japan's Kagoshima and Okinawa prefectures, which have state-designated jurisdiction over the area that is located just east of what Japan claims is the median line separating the 200-nautical-mile exclusive economic zones (EEZ) of Japan and China in the East China Sea.

Teikoku Oil originally applied for exploration rights in the region in 1969 and 1970. However, the government shelved the applications because of unsettled EEZ demarcation in the sea between Japan and China.

China does not accept and acknowledge the median line since it was unilaterally drawn by Japan without discussions with China. The EEZ is claimed by China on a continental shelf basis. It has lodged an official protest with Japan over the Teikoku concessions.

The two countries have held talks but have yet to resolve the territorial dispute.

Supporting New Zealand's E&P

Over the next 12 to 24 months there is likely to be an increasing level of oil and gas exploration activity both on and offshore New Zealand. To support the demand for acreage, Crown Minerals plans to progressively increase the number of permits available for bidding by way of blocks offers. In addition to the current blocks being offered in the Outer Taranaki and Northland basins, anticipated block offers for the next 12 months will be located offshore the East Coast and offshore Taranaki in 2005 and, in 2006, onshore Taranaki and onshore the East Coast.

The exact number and location of these blocks will be determined nearer the time of announcement, and some may be contingent on the surrender of some currently permitted areas. If additional prospective acreage in other basins is released during this period, additional blocks offers may also be announced, states Crown Minerals.

exploration joint venture agreement with Medco Energi International, Indonesia's largest independent exploration and production company. Under the agreement, Anadarko subsidiaries are gaining access to 13 production sharing contracts totalling 7.8mn acres onshore and offshore Sumatra, Kalimantan, Sulawesi, Java and Papua.

The government of India has awarded *Cairn Energy and its joint venture partners five new exploration blocks on and offshore India, including two new areas in Rajasthan, under the fifth New Exploration Licensing Policy round (NELP V). In competitive bidding there were a total of 69 bids for 20 exploration blocks in the round, with bids from 26 foreign companies including Cairn.*

LATIN AMERICA

Repsol YPF has acquired three oil fields *and one gas field in Trinidad and Tobago from BP for $229mn. Trinidad and Tobago state oil company Petrotin will purchase a 15% stake.*

Argentina's second largest oil and gas *producer Pan American Energy is being lent $250mn by the International Finance Corporation, helping fund the BP-Bridas Corporation joint venture's 2005 capital expenditure programme, focused on the Golfo San Jorge basin, southern Argentina, reports* Keith Nuthall.

AFRICA

Shell has made discoveries in two 'Big *Cat prospects' offshore Nigeria. The wells, in blocks OPL 322 and OPL 245, were both in frontier areas.*

Nigerian President Olusegun Obasanjo *is reported to have promoted his Oil Adviser, Edmund Daukoru, to Junior Petroleum Minister in a broad cabinet reshuffle. The President retains his position as Petroleum Minister, which he has held since his election in 1999.*

Yemen's Nabrajah field in block 43 has *come onstream at an initial rate of some 5,000 b/d – a figure expected to ramp up to 50,000 b/d by 4Q2006. Proven plus probable oil reserves are put at 68mn barrels.*

Pan-Ocean Energy is understood to *have brought onstream its Tsiengui field onshore Gabon at an initial rate of 2,400 b/d.*

Centrica acquires North Sea assets

Centrica has reached agreement with Kerr-McGee to acquire its non-operated interests in four producing gas fields – Andrew, Brae, Buckland and Skene – in the northern and central North Sea, adding approximately 1.1bn therms of gas and 11mn b of oil to Centrica's portfolio. The company will also acquire interests in future exploration opportunities in the licence blocks and a development option which could add significant reserves on the Andrew field.

Approximately 70% of Centrica's equity gas in the fields would be uncontracted and it will also benefit through tariff income from its interest in the SAGE pipeline transporting gas from the northern North Sea.

Gas from the Brae, Buckland and Skene fields is exported to the St Fergus SAGE terminal, with gas from Andrew delivered to the Teesside terminal via the CATS pipeline system.

Upon completion of the agreement in 3Q2005, Centrica will hold the following interests:

- Andrew (operator BP) 6.66%
- Brae (operator Marathon) 8%
- Buckland (operator ExxonMobil) 33%
- Skene (operator ExxonMobil) 33%
- SAGE pipeline system (operator ExxonMobil) 4%

Oil sands expansion for Total

Total is to acquire all of the common shares of Deer Creek Energy for C$1.35bn (about $1.11bn) under a friendly offer that has been unanimously approved by the Board of Directors of Deer Creek Energy.

Deer Creek Energy has an 84% interest in the leases of the Joslyn oil sands project in the Athabasca region of Alberta, Canada. Joslyn will be a multiphase development with estimated cumulative production of around 2bn barrels of bitumen over 30 years. The majority of the resources will be recovered using open pit mining techniques. In-situ steam-assisted gravity drainage (SAGD) technology will also be used.

An application will be submitted to the Alberta authorities (Alberta Energy and Utilities Board – AEUB) in early 2006 for the first phases of the mine and related extraction facilities. The mining operations will be a large-scale development. Production from the mine is scheduled to begin in 2010 and, following several phases, reach a plateau of 200,000 b/d of bitumen.

The first two phases of SAGD development have already been approved by the AEUB. Currently in its start-up stage, the pilot project is targeted to become commercial in 2006, with a production of about 10,000 b/d. Further phases are under study to take production to a significantly higher level.

The Joslyn project will include downstream operations to further process the bitumen to improve the added-value of the products. Downstream operations are likely to include upgrading in Alberta. It is expected that downstream synergies could be drawn from Total's equity production of the Joslyn project and other oil sands leases.

Total also owns a 50% interest in the Surmont SAGD project in Alberta and is a major player in extracting and converting heavy oil through its 47% participation in the Sincor project, in Venezuela – one of the world's largest developments of its type – which produces more than 200,000 b/d.

Usan field development plans

Total's Nigerian subsidiary, Elf Petroleum Nigeria Ltd (EPNL; 20%) has drilled two appraisal wells in the Usan field in deepwater oil prospecting licence (OPL) 222, offshore south-eastern Nigeria. The Usan field was discovered in 2002 and, in 2004, a western extension was confirmed by the drilling of Usan 5 and 6. This year, Usan 7 and 8 confirmed an eastern extension of the field.

Usan's field development plan has been approved by Nigerian National Petroleum Corporation (NNPC), the concessionaire of the licence. Additional approval will be sought from the Department of Petroleum Resources in the near future. The plan includes 35 subsea wells connected to a 2mn barrel capacity floating, production, storage and offloading (FPSO) vessel with a processing capacity of 150,000 b/d of oil. First oil is planned by 2010.

Project partners are Chevron Petroleum Nigeria (30%), Esso Exploration and Production Nigeria (30%) and Nexen Petroleum Nigeria (20%).

NNPC has also signed a production sharing contract with EPNL for the development of a deep offshore oil block in OPL 223. Elf is expected to pay a signature bonus of $7.6mn, writes *Stella Zenkovich.*

UK

The UK government has published its *UK Energy Sector Indicators 2005, used to monitor progress towards the policy goals of the 2003 Energy White Paper, at* **www.dti.gov.uk/energy/inform/energy_indicators/index.shtml** *In addition, the third annual* UK Fuel Poverty Strategy Progress Report *has also been published – copies can be found at* **www.dti.gov.uk/energy/consumers/fuel_poverty/fuel_strategy.shtml**

BP's 2Q2005 replacement cost profit *was $4,981mn compared with $3,873mn a year ago, an increase of 29%. For the half year, profit was a record $10,472mn, up 29%.*

Shell has posted a 2Q2005 net income *of $5.3bn, a 34% increase from 2Q2004. 1H2005 income was $11.9bn, up from $8.6bn in 1H2004.*

Centrica has become a 20% partner in *the Canvey LNG project, which proposes to convert an existing LPG terminal at Canvey Island, Essex, into an LNG receiving facility.*

EUROPE

The merger of Royal Dutch Petroleum *and Shell Transport & Trading to form Royal Dutch Shell has been approved by the UK's High Court. Shell has now acquired over 95% of Royal Dutch Shares and it is seeking delisting from Euronext Amsterdam and from the New York Stock Exchange.*

Gasunie and Vopak have commenced *a feasibility study into the possible development of an LNG receiving terminal at a location in the north-west part of the Maasvlakte at Rotterdam.*

NORTH AMERICA

Lee Raymond, Chairman and Chief *Executive Officer of ExxonMobil is to retire at the end of this year after more than 42 years of service, including over 21 years as a Director. It is anticipated that ExxonMobil President, Rex Tillerson, will succeed Raymond.*

Dynegy is understood to be planning *the sale of its natural gas processing business to Houston-based Targa Resources for some $2.5bn.*

ConocoPhillips has reported a 2Q2005 *net income of $3.1bn, up from $2bn in 2Q2005. 1H2005 income was $6bn.*

Chevron/Unocal merger completes

Chevron has completed its merger with Unocal. The combined company will produce approximately 2.8mn boe/d, including production from oil sands, production under operating service agreements and the company's share of production by equity affiliates. The merger will increase Chevron's proved reserves (based on year-end 2004 reporting and including the company's share of equity affiliates) by more than 15%.

Unocal's key areas of operations in the Asia-Pacific and Caspian regions, and the US Gulf of Mexico, make a strong strategic fit with Chevron's existing core areas of operations. In the Asia-Pacific region, which is anticipated to be one of the world's strongest economic growth areas, the combined company will generate more than 20% of its equivalent daily crude oil and natural gas production. The company will also be a leading resource holder in this region.

The strong strategic fit between the two companies is expected to provide for a rapid and efficient integration, for which planning is complete. To date, the company has confirmed the continued employment of more than 5,000 Unocal employees. Chevron intends to make employment offers to many of the remaining 1,400 Unocal employees and to conclude the selection process by the end of September.

Charles Williamson, Unocal's Chairman and Chief Executive Officer, will join Chevron in a transition role until later this year. He will be an Executive Vice President of the corporation, assisting with the integration of the two companies.

'Gas Opec' not yet on the agenda

The recent meeting of the Gas Exporting Countries Forum (GECF) has rekindled fears amongst consuming nations that a 'gas Opec' is soon to materialise. However, according to independent analyst Datamonitor, this is an 'overblown fear', at least in the short to medium term, due to the loosely defined nature of the GECF, its disparate membership, current market dynamics and the widely conflicting agendas of the membership.

Membership has fluctuated since the group's formation in 2001. It currently consists of Algeria, Bolivia, Brunei, Egypt, Indonesia, Iran, Libya, Malaysia, Nigeria, Norway (as an observer), Oman, Qatar, Russia, Trinidad & Tobago, the United Arab Emirates and Venezuela. Together, these countries account for 73% of the world's gas reserves and 41% of production. According to Datamonitor Energy Analyst Andrew Hill: 'Whilst this collective strength represents a formidable force and significant potential to influence the global gas sector, the impact of the GECF remains limited, particularly given the organisation's informal structure and apparent lack of cohesion. GECF members are under few, if any, obligations to either attend meetings or adopt policies decided by the meetings. Further to this, the disparate agendas and motivations of the members mean that even deciding, let alone implementing, policy matters is a slow process which has enjoyed limited success so far.'

'The members are in fact very different with regard to production capabilities, reserves, the role gas plays in their economies, and the markets they sell into. This diversity of interests and motivations creates conflicting interests of the type seen over the years in the oil markets with Opec,' states Hill. These differences manifest themselves most acutely in terms of the member's reserves and production profiles and the resultant differing agendas these positions produce.

'If the GECF were to operate as a gas cartel along the lines of Opec, big producers such as Russia and Qatar – which together account for around 25% of global gas production and 41% of reserves – would be unlikely to have sufficient motivation to hold back supply to support or uplift prices given that their huge gas resource endowments motivate them to make money on volume rather than on price. Conversely, members with smaller gas industries such as Libya will be more concerned with high prices in the short term rather than making money on volume.'

Furthermore, the potential for the GECF to act as a cartel is somewhat hampered by the current nature of gas contracts, Hill says. 'Despite the ongoing process of liberalisation, gas in many parts of the world continues to be traded on long-term contracts, often 10 or even 20 years in length. Only when gas markets have predominantly moved away from these arrangements towards a more spot and forward market-based system will there be significant scope for a gas Opec to influence gas prices through production programming in the way that Opec influences the oil market.'

Eni has signed an agreement with *Sempra to buy a share in the Cameron LNG terminal that Sempra LNG is building along the Calcasieu River in Louisiana, US. The contract is for 20 years. Eni will acquire regasification capacity of 6bn cm/y, 40% of the overall capacity of the terminal. The LNG plant will be commissioned by the end of 2008 and have a processing capacity of some 15.5bn cm/y.*

MIDDLE EAST

Another Volcker panel report into the *UN Oil-for-Food scandal has accused its former director Benon Sevan of receiving programme-linked bribes worth $147,184 from 1998–2002, writes* Keith Nuthall. *The inquiry found a Sevan-associated company African Middle East Petroleum (AMEP) lifted 7.3mn barrels of Iraqi oil under the programme, generating $1.5mn revenue, of which $580,000 was paid to an account controlled by Fred Nadler, (brother-in-law of former UN Secretary General Boutros Boutros-Ghali), from which 'nearly $150,000... was deposited to... bank accounts of Mr Sevan' (and his wife).*

RUSSIA/CENTRAL ASIA

Lukoil and the European Bank of *Reconstruction and Development (EBRD) have concluded a $180mn loan agreement for 12 years which will be used to finance the offshore Shakh Deniz gas condensate project in the Azeri sector of the Caspian Sea and construction of the South Caucasian Pipeline linking Baku, Tbilisi and Erzerum.*

ASIA-PACIFIC

A new tank-and-siphon system *removing oil from water will soon be launched internationally, writes* Monica Dobie. *The University of New South Wales, Australia, developed, Extended Gravity Oil Water Separation (EGOWS), removes oil to below 10 parts per million, requires no power and can be used unattended. EGOWS improves on the 60-year-old, industry-standard, American Petroleum Institute gravity separator.*

Amerada Hess is to sell to PTT in excess *of 500bn cf of natural gas from the Phu Horm field in north-east Thailand over a 15-year period. First gas is expected to be delivered before the end of 2006 at an initial rate of approximately 80mn cf/d, increasing gradually to an expected rate of in excess of 100mn cf/d.*

Price of UK ROCs set to rise

The price of renewable obligation certificates (ROCs) in the UK is set to rise largely because of delays to windfarm projects, with the new Platts ROC Marker predicting ROC prices of over £47/MWh for the next two years. This is a substantial 14% increase on predictions made in June last year.

The main factors behind the increases are a slowdown in the rate of progress of many onshore wind projects through the planning process. Other factors have increased the value of ROCs too. Significantly, electricity demand is higher than that predicted by the government, states Platts.

The price of ROCs depends on the balance between electricity generated from renewable plants and the total electricity demand of UK customers. Electricity suppliers have to provide a proportion of their electricity from green projects. ROCs are used as a 'proof of purchase' to show that this has been accomplished.

The current high prices of ROCs means that existing renewable generators and coal-fired power stations that burn biomass should be seeing a substantial increase in earnings this year. According to analysis published in *Platts Power UK*, a typical 2-GW generator could make around £13mn/y in profit from electricity produced by burning assorted biomass fuels for which it can obtain ROCs, levy exemption certificates and avoid paying carbon certificate costs.

The Platts ROC marker predicts that prices could rise further over the next few years if fewer than expected offshore windfarms are built. The marker predicts that the value of ROCs could rise to over £61/MWh in five years' time. However, if more projects go ahead, prices will remain closer to previous predictions. In the middle growth scenario, ROC prices are around the £41/MWh level. Only in the high growth scenario, where most projects in planning go ahead as scheduled, do prices fall below the £30/MWh level.

Recent European Union developments

Proposals to build a Baltic Sea gas pipeline straight from Russia to Germany has outraged neighbouring eastern Europe countries, such as Poland, reports *Keith Nuthall*. Both it and the Baltic States are pushing for the plans to be discussed at European Union (EU) level as they would threaten common-EU policies to guarantee energy supplies to all Europe.

In other EU news:

- **The European Investment Bank (EIB) is planning to lend 149.6mn to utility Viesgo Generación to build a large natural gas-fired combined cycle generating plant in Spain, generating around 800 MWe. The EIB also wants to lend 200mn to Syri's Public Establishment of Electricity for Generation and Transmission (PEEGT) to build a combined cycle gas turbine of 750 MW in the country's north-east.**
- **The European Bank for Reconstruction and Development (EBRD) is planning to lend $72mn to Italy's Pietro Barbaro River Shipping Company to buy eight tankers and five barges to transport oil products on Russian rivers. The EBRD also plans to lend $50mn to Kazakhstan's KazTransGas Distribution (KTGD) to rehabilitate gas distribution pipelines and install meters in the south of the country.**
- **Italian researchers, coordinated by the University of Trieste, have developed a new technique for producing hydrogen whilst purifying polluted gases using cerium oxide, a powder used in ceramics and glass polishing. Visit** www.sissa.it/main/_communication/com_st_SISSA_29_lug_2005_ceria_fabris_eng.pdf

Development of UK renewables

Speaking at the official opening of Scottish and Southern Energy's 20-MW wind development at Artfield Fell in Dumfries and Galloway at the end of July, UK Energy Minister Malcolm Wicks announced the publication of a consultation document that he stated 'will have a major impact on how the sector develops in future'.

The document outlines the proposals for giving renewable developers on the Scottish islands of Shetland, Orkney and the Western Isles a discount on the charges they will have to pay to use the high voltage transmission grid. The islands are not connected to the transmission network yet, but all three have great potential for renewable development. The consultation document will also present the results of the study commissioned by the UK Department of Trade and Industry (DTI) from independent consultants on the impact of transmission charges on renewable generation in the north of Scotland.

UK

UK households could save a collective *£6bn on their energy bills by adopting simple energy-saving measures in the home such as insulating their property and installing energy-saving light bulbs, according to the Energy Saving Trust.*

UK grain trader Wessex Grain has *joined forces with five other European companies in a move to promote the development of bioethanol fuel across Europe. Working alongside companies from Spain (Abengoa Bioenergy), Germany (Sudzucker Bioethanol, KWST), Sweden (Agroetanol) and the Netherlands (Nedalco), it has founded the European Bioethanol Fuel Association (eBio). The aim of eBio is to promote the benefits of bioethanol, such as reducing greenhouse gases and increasing energy supply security, while protecting the interests of the industry by reducing regulatory barriers that prevent its development. Increasing public knowledge and awareness will also be central to the new association's campaign.*

EUROPE

Shell and Bechtel have completed the *sale of InterGen, with divestment proceeds to Shell exceeding $1bn and contributing to Shell's $12bn–$15bn divestment programme for the period 2004–2006. InterGen was sold to a partnership between AIG Highstar Capital II and Ontario Teachers' Pension Plan for $1.75bn.*

Foster Wheeler's Italian subsidiary and *the Swiss company Methanol Casale have formed what they claim is a*

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Competition leads to rethink from European utilities

A year after the small and medium enterprise (SME) energy market was fully opened to competition throughout the EU, the region's utilities are facing a rethink of how they approach this market segment. Recent research from independent analyst Datamonitor reveals that many SME suppliers are overspending on customer service in relation to the level of competition in their market – either because effective competition has not yet emerged, or because, on the contrary, it has developed to a point where service improvements are eroding suppliers' profit margins.

Datamonitor's report analyses the state of play in energy supply to SME customers in key western European markets such as the UK, Germany, France, Spain, Italy, the Netherlands and Scandinavia. The analysis and recommendations to suppliers are based on a combination of over 30 in-depth executive interviews.

'Customers in the recently liberalised – and even in the more established – markets are generally unaware of the benefits of supplier switching and/or apathetic, in view of the savings on offer in relation to the hassle of switching,' according to Datamonitor's Utilities Analyst Mikhail Masokin. 'In the absence of substantial discounts and trusted alternatives to the incumbent supplier, customer activity tends to be limited to contract re-negotiation, with a view to achieving a price reduction. Service standards in place at most utilities are already more than sufficient to prevent significant leakage of customers for service reasons. This limits the scope for non-price competition in the SME segment. The exception to this is in billing – a supplier that makes repeated mistakes in this area can expect to lose business'.

On the other hand, price competition in France, Italy and Spain in the next three years will also be minimal in what are essentially re-seller markets. The remaining regulated tariffs remain very keen, making it very difficult for the new entrants to undercut them.

'However in the UK, Netherlands and Scandinavia, customer activity will be supplier-led, with slightly more scope for price-based competition, especially in light of the recent price rises by incumbents such as Centrica,' Masokin says. 'German customer switching is unlikely to pick up in the short term, as the new energy regulator will require time to fully resolve the problem of discriminatory access charges.'

By 2008, most leading EU markets will become more competitive.

The report also reveals that the SME customer base is too diverse to paint with a single brush. Instead, the different sub-segments require different marketing channels and customer targeting strategies in order to be successful, according to Masokin. 'The volume of deals and large-sized utilities' M&A [mergers and acquisitions] activity has slowed down following the dash for scale in the mid-1990s. Future M&A is likely to be smaller in scale and strategic, as utilities place more focus on stakeholder value than on empire-building, as in the recent past. Under these circumstances, utilities should work on improving cost efficiencies and on customer retention as the key strategies going forward from 2005 to 2006 and beyond.'

US economic incentives for ultra-clean fuels

Syntroleum reports that two bills recently signed by President George Bush provide 'significant economic incentives for the development of ultra-clean fuels derived from coal using Fischer-Tropsch (FT) technology such as the Syntroleum(R) process'.

The Energy Policy Act of 2005 (EPAct 2005) authorises a $1.6bn allocation for research and development funding of clean-coal initiatives, including the production of ultra-clean fuels. In addition, the legislation provides for loan guarantees associated with the construction of commercial scale coal-to-liquids (CTL) plants.

The second piece of legislation, entitled the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005 (SAFETEA), provides a 50 cents per gallon excise tax credit for alternative fuels. This includes ultra-clean FT fuels made from coal.

According to Energy Information Agency (EIA) data, the US is the largest coal reserve holder in the world. If only 5% were utilised to produce ultra-clean transportation fuels, it would be equivalent to the oil reserves in the US.

'groundbreaking strategic alliance' under which the two companies will cooperate to serve the methanol production market worldwide. Methanol production is projected to grow steadily over the next few years and could accelerate if new applications for methanol, such as dimethyl ether (DME) and methanol-to-olefins (MTO), take off quickly.

***Distribution and logistics company** Topaz is understood to have acquired the fuel retail and commercial business of Shell in the Republic of Ireland and Northern Ireland for an undisclosed sum. Shell owns six oil import facilities in Dublin, Cork, Limerick, Galway, Derry and Greenore; 35 local distribution depots geographically spread across Ireland; 55 service stations and also supplies 105 independently-owned service stations in the country. The Shell brand will continue to be associated with the businesses under the new owners.*

***Foster Wheeler has signed a frame** agreement for the provision of engineering services for Italiana Energia Servizi (IES), owner of the Mantua refinery in northern Italy. The terms of the award were not disclosed.*

***BASF and Shell Chemicals have com**pleted the sale of their 50:50 joint venture Basell – one of the world's leading manufacturers of polyolefins – to Nell Acquisition, an affiliate of New York-based Access Industries. The sale price totals 4.4bn, including debt.*

MIDDLE EAST

***Saudi European Petrochemical Company** (an affiliate of SABIC) has signed a letter of intent with Aker Kvaerner for the provision of programme management services and basic engineering services for its Ibn Zahr polypropylene III project, located at its existing site in Al-Jubail, Saudi Arabia. A new polypropylene line will be built with a capacity of 500,000 t/y, nearly doubling current capacity.*

***LG International is to set up an aro**matics joint venture with two Omani oil operations. The company will invest $60mn for a 20% stake in the $300mn Aromatics Oman venture. Oman Oil will own a controlling 60% interest in the company, with Oman Refinery holding the remainder, reports* Stella Zenkovich.

***On behalf of Yanbu National** Petrochemical Company (YANSAB), Saudi Basic Industries Corporation (SABIC) has signed a letter of intent*

UK energy statistics for 2004

The *2005 Digest of United Kingdom Energy Statistics* has been published by the UK Department for Trade and Industry (DTI) providing comprehensive data for 2004 and an account of trends in energy supply and demand in the UK. The publication is available at **www.dti.gov.uk/energy/inform/dukes/** Included with the Digest this year are the booklet *UK Energy in Brief*, which summarises the latest energy statistics in 29 charts, and the *2004 Energy Flowchart*, which illustrates the flow of fuels from production or import to eventual final use.

The main trends in energy in 2004 include:

- An overall decrease in indigenous energy production of 8.5% and an increase in primary energy consumption of 1% in the UK. As a result, overall primary fuel consumption was not met by indigenous production and the UK became a net importer of fuel for the first time since 1992.
- Increased energy consumption and lower nuclear output meant that, provisionally, emissions of carbon dioxide rose by 1.5% in 2004.
- A lower gas-coal price differential decreased the commercial attractiveness of coal for electricity generation, and increased the amount of electricity generated from gas. Gas accounted for 40% of electricity generation.
- Refinery output increased by 6% and petroleum product exports increased by 30%.
- Electricity generated from renewable sources in the UK in 2004 represented 3.6% of total UK electricity generation, up from 2.7% in 2003.

The DTI has also published *Energy Consumption in the United Kingdom 2004* – available at **www.dti.gov.uk/energy/inform/energy_consumption/**

New credit risk guidelines published

The need for energy market participants to manage efficiently their credit and other risks is critical to market and counter-party confidence. With this in mind, the Power Trading Forum (PTF) of the UK's Futures and Options Association (FOA), in association with Clifford Chance and Ernst & Young, recently published new credit risk guidelines. These provide comprehensive recommendations designed to assist organisations engaged in energy market trading to better understand the nature and consequences of credit risk and the primary techniques for measuring and mitigating that risk.

The guidelines emphasise Board responsibility in terms of setting credit risk management policy and identify the kind of practices and procedures which are necessary for measuring, managing and mitigating credit risk, including, for example, the use of collateral, master netting agreements, letters of credit, etc.

For the Executive Summary and to download a full copy of the report visit **www.foa.co.uk/publications/guidelines/creditriskguidelines-july05.pdf**

Miller Oils launches new lube range

Millers Oils has launched a fully synthetic range of competition diesel engine oils, highlighting its ongoing focus on product development within the Millers Motorsport range. The three products are each fully formulated synthetic base fluids, which have been combined with the latest in additive technology to provide maximum engine performance for the end-user.

DFS 10w60 and DFS 15w60 have been designed for competition engines that typically run in highly stressed, endurance conditions, while DFS 10w40 has been developed for diesel engines where maximum performance and protection is required.

Each of the three oils is claimed to provide increased load carrying capacity, high film strength for ultimate protection and outstanding cold flow properties, to protect against wear at start-up, as a result of the incorporation of new triple ester technology, which enhances thermal stability for oxidation resistance and minimises friction losses in the engine – leading to better output compared to an equivalent non ester oil.

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with Aker Kvaerner for the engineering, procurement and construction of a world-scale polyolefins complex, in Yanbu, Saudi Arabia. The project is to be executed on a joint venture basis with Sinopec. The new facility will include a polyethylene plant and a polypropylene plant, together with the associated product handling facilities. The new plants, part of a major new ethylene complex, will each have a nameplate capacity of 400,000 t/y. The complex is expected to come onstream in April 2008.

ASIA-PACIFIC

***Reliance Industries is reportedly** planning to spend $5.7bn on doubling capacity at its Jamnagar plant in western India by 2H2009, to create what it claims will be 'the world's largest oil refinery'.*

***El Paso Corporation is understood to** have agreed to sell several of its Asian power assets to a subsidiary of Globeleq for $109mn. The assets include power plants in Pakistan, Indonesia, Bangladesh, and the Philippines. El Paso is targeting a reduction in company debt, net of cash, to approximately $15bn by year-end 2005.*

***China Power Investment Corporation** (CPIC) is reportedly planning to build a total of ten 1,000-MW nuclear reactors on the eastern coast of Liaoning and Shandong provinces in a bid to reduce the country's reliance on coal. The Chinese government has set an ambitious target of building at least two new reactors a year. By 2020, 4% of the country's power needs will be supplied by nuclear energy, compared with 2% currently, from nine reactors in the Zhejiang and Guangdong provinces. Two further reactors are currently under construction in East China's Jiangsu province, bringing China's total capacity to about 9,000-MW.*

AFRICA

***Nigeria's Directorate of Petroleum** Resources (DPR) has given Obat Oil and Petroleum approval to construct a 120,000 b/d refinery in Erunna, Ilaje Ese Odo, Ondo state. The first phase of the project is likely to come onstream in late 2007, reports* Stella Zenkovich. *Meanwhile, a private sector-driven company – TransCorp – has been formally unveiled, with the Federal Government granting it immediate approval to build a $250mn refinery in Lekki Free Port Zone, Lagos.*

Indian companies to look at Romania

Indian Petroleum Minister Mani Shankar Aiyar, confirming that local state-owned oil companies will have to get used to an administered price regime for the retailing of petroleum products such as petrol and diesel in the domestic market for an indefinite period under a government directive, believes there is a chance for such companies to shore up revenues through acquiring stakes in Romanian refineries and exports to the EU, writes *Stella Zenkovich*. 'Romania is willing to allow us to come in either through the privatisation route or through joint ventures,' he stated in the wake of a week-long trip to Turkey and Romania as the head of a delegation including representatives from the Confederation of Indian Industry.

The Romanian government is keen to modernise its 10 refineries in a bid to meet the requirements of Euro IV and Euro V standard fuel specifications by 2007 and 2009. The country is expecting to become a member of the European Union by 1 January 2007.

Coal-to-liquids development deal

Syntroleum has signed a memorandum of agreement (MoA) with Australian-based Linc Energy to pursue the development of a coal-to-liquids (CTL) project using the Syntroleum® process in Queensland, Australia. The agreement, which integrates air-based Fischer-Tropsch (FT) technology with Linc Energy's underground coal gasification (UCG) expertise, is part of Linc Energy's ongoing Chinchilla project, which also includes early development of an integrated a power plant.

The UCG process utilised at the Chinchilla facility is similar to commercial techniques used in Russia for over 30 years. It involves injecting air and steam into an underground coal seam through a series of boreholes and igniting the coal *insitu*. The coal seam is gasified and hot product gas containing the key feedstock for power generation or FT synthesis (hydrogen and carbon monoxide, or synthesis gas) is produced via a second series of boreholes.

The UCG syngas, which undergoes sulphur removal and additional conditioning at the surface, is similar to syngas obtained from conventional surface coal gasification systems, but production is achieved at a much lower cost. Underground sequestration of carbon dioxide (CO_2) is often an important component of commercial designs. The coal-derived syngas is burned in gas turbines to produce power or is used as feedstock for FT reactors and refining processes to make ultra-clean diesel fuel.

The first commercial phase of the Chinchilla project, which Linc Energy plans for next year, involves installation of a 30–40 MW power plant that will provide electricity to local markets. The second commercial phase of the project, which plans for a 17,000 b/d Syntroleum CTL plant and power plant expansion, will be developed over the next few years.

New SUV fuel quality standards in EU

New fuel quality standards for vehicles sold in the European Union (EU) from 2008 have been published by the European Commission, which will stop sports utility vehicles (SUVs) operating under laxer emissions rules applying to commercial vans, writes *Keith Nuthall*. Instead, under the so-called Euro 5 plan, they would follow tougher regulations for cars. Also, the plan would reduce emissions of both nitrous oxides (NO_x) and hydrocarbons by 25% for cars running on petrol; particulate pollution from diesel cars would fall by 80% and NO_x 20%.

Green light for Scottish hydro project

The Scottish Executive is reported to have given Scottish and Southern Energy (SSE) the green light for construction of what is claimed will be the largest hydroelectric power station to be built in Scotland for almost 50 years.

The £140mn project at Glendoe, near Fort Augustus, will be capable of generating enough green electricity to power 250,000 homes. It will play an important role in meeting the Scottish government's target of generating 40% of Scottish electricity from renewable sources by 2020.

The 100-MW plant will be Scotland's second largest conventional hydroelectric station and the first large-scale station to be built since 1957, when the Errochty station in Perthshire, which has a capacity of 75 MW, was opened.

The new facility is due to be commissioned in the winter of 2008.

Photo: Oyvind Hagen/Statoil

Struggling to slow North Sea depletion

Recent exploration success in the North Sea has been muted and largely confined to the Norwegian sector, writes Chris Skrebowski. *However, in terms of new developments, existing producers and new entrants have been forging ahead, building production centres and exploiting all the small accumulations within tieback range. High oil prices provide a significant incentive to develop the area's remaining reserves, while the major production infrastructure is still in place.*

	2000	2001	2002	2003	2004	2005*	2006*
Norway	3,346	3,418	3,330	3,264	3,188	3,010	3,000
UK	2,667	2,476	2,463	2,257	2,029	1,890	1,690
Denmark	364	347	372	371	394	400	390
Netherlands**	20	35	46	47	43	40	37
Germany**	36	38	40	40	40	40	40
Total	**6,427**	**6,314**	**6,252**	**5,979**	**5,694**	**5,380**	**5,157**

Source: BP Statistical Review *June 2004 except* * IEA Monthly Oil report *July 2005*
** Petroleum Review *estimate*

Table 1: North Sea oil production (,000 b/d)

	2000	2001	2002	2003	2004
Norway	49.7	53.9	65.5	73.1	78.5
UK	108.4	105.8	103.6	102.9	95.9
Denmark	8.1	8.4	8.4	8.0	9.4
Netherlands	19.8	20.0	20.0	23.0	29.0
Total	**186**	**188.1**	**197.5**	**207.0**	**212.8**

Table 2: North Sea gas production (bn cm)

According to the latest *BP Statistical Review*, oil production in the Norwegian sector of the North Sea fell by 2.1% in 2004, while in the UK sector it fell by a staggering 10%. Only the small Danish sector managed to grow production in 2004, by 3.3% (see **Table 1**). Yet, despite this somewhat gloomy background, there remains a considerable commitment to the region, with investment levels rising, oil prices high and a number of smaller companies working hard to show that their innovative approaches can produce results. Massive rationalisations of acreage holdings are also occurring, driven partly by legislation.

The picture for gas production (**Table 2**) is rather more positive, with strong gains in Norwegian, Danish and the Netherlands offshore output. The notable exception is the UK sector, where gas production fell back by 6.7% in 2004, turning the UK from a small net exporter to a small net importer (production 95.9bn cm, consumption 98bn cm). This trend is set to continue, with annual declines of around 6%/y. By 2010, according to the UK Offshore Operators Association (UKOOA), production could be as low as 110mn cm/d (40bn cm/y), or as high as 170mn cm/d (62bn cm/y). This supply shortfall is set to be made up by imported gas from the Norwegian Ormen Lange field via the Langeled pipeline; by LNG imports into the Medway and Milford Haven; and via the existing Interconnector to Bacton and the new Belzgand-Bacton Interconnector.

Further expansion of gas production in the Danish and Dutch sectors is likely to be fairly limited over the next few years, but Norwegian gas production is set to expand steadily, with the Snohvit development supplying LNG from 2006 in addition to pipeline supplies. Current expectation are that Norwegian gas production could reach 110–130bn cm/y towards the end of the decade.

Future oil production

Looking to future oil production, **Table 3** clearly shows that in the UK sector future projects are predominantly small, often little more than off platform outstep wells. Next year, 2006, will see the start-up of the largest undeveloped oil field in the UK sector – Buzzard. This 460mn barrel field is expected to peak at 180,000 b/d (200,000 boe/d) in 2007. The only other significant UKCS producers to come onstream in the next year or two are Brodgar and Callanish (60,000 boe/d) and Tweedsmuir (30,000 boe/d).

Although UKOOA is optimistic that production decline can be stabilised for a year or two if all the possible and probable developments go ahead, others are rather more sanguine. The International Energy Agency's (IEA) latest projection is that the UK sector will see a production decline of over 100,000 b/d in 2005 and up to 200,000 b/d in 2006. With UK oil consumption of around 1.7mn b/d, the IEA's projections imply the UK becoming a net oil importer in 2007/2008, while UKOOA's more optimistic view could delay the date to 2009/2010.

For the companies operating in the UK sector the pressure is now really on to develop as many as possible of the remaining fields while the major infrastructure of platforms and pipelines are still in place. The fact that currently virtually all the available rigs in the area are at work confirms that almost all that can be done is being done. The financial incentive of high prices is clear enough. The incentive/disincentive effect of taxation is discussed on p20.

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
UK onstream 2004								
*Alba Extreme Sth Ph2	oil	Chevron	Oct-04			3 subsea to Alba	17,000 b/d (av-05)	
*Broom (ex W Heather)	oil	block 2/5	Lundin Oil	Aug-04	36mn b		3 prodn,2 inj t/bk to Heather	20,000+ b/d (05)
*Boulton H (CMS III)	gas	44/21b	ConocoPhillips	Mar-04		106bn cf	via Caister Murdock (CMS)	140mn cf/d
*Calder (Rivers I)	gas	110/7a	Burlington	Oct-04	2mn b (cond)	350-400bn cf	NNM platform	80mn cf/d (06)
*Goldeneye	gas/cond	14/29a, 20/4b	Shell	Oct-04	17mn b (cond)	500bn cf	NNM plat,105km t/b St Ferg	30,000 b/d (05), 300mn cf/d (05)
*Helvellyn	gas	47/10b	ATP	2004		50bn cf	subsea to Amethyst platform	36mn cf/d (for 5 years)
Howe	oil	22/12a	Shell	Nov-04	15mn b	5bn cf	subsea tieback to Nelson	13,000 boe/d
*James	oil	30/17a	Kerr-McGee	Nov-04			subsea tieback to Janice	initial 8,000 b/d
*Nethan	oil/gas	30/17b	Talisman	2004				
*Playfair	oil/gas	211/19	CNR	2004			ERW from Murchison	
*Rose	gas	47/15b	Centrica	Jan-04		88bn cf	subsea via Amethyst	
*Scoter	gas/cond	22/30a, 23/26	Shell	Mar-04	3mn b or 40mn boe	200bn cf	tieback to Shearwater	6,000 b/d (04), 120mn cf/d (04)
*Tartan North	oil	15/16a	Talisman	Aug-04			1 subsea well to Tartan	10,000 b/d (05)
*Valkrie	gas	49/16	ConocoPhillips	Aug-04		70bn cf	ERD fromVampire	90mn cf/d (05)
Onstream 2005								
*Annabel	gas	48/10c	Venture	Apr-05		96bn cf	subsea to Audrey A/Loggs	60mn cf/d (06)
Artemis (Juno)?	gas		BG	2005		70bn cf		
*Arthur	gas	53/02	ExxonMobil	Jan-05		130bn cf	subsea via Thames	110mn cf/d (05)
*Atlantic & Cromarty	gas/cond	13/30a, 14/26a	BG/Am'rda Hess	late 2005	3mn b (cond)	250bn cf	t'bk to Goldeneye/St Fergus	220mn cf/d (06)
*Brechin	oil	22/23a	Paladin	Jul-05	10mn b		subsea via Arkwright	
Broom Ph2/N Terrace?	oil	block 2/5	Lundin Oil	4Q2005			2 subsea to Heather	
Bruce (upgrade)?	gas/cond		BP	Apr-05			additional compression	
Caravel (Cleaver Bank)	gas		Shell	2005	390bn cf	platform		
*Clair South	oil	206/7a, 8, 9, 12, 13a	BP	Feb-05	250mn b (Phase1)	106bn cf	1 steel plat, gas to Magnus	60,000 b/d, 15mn cf/d (05)
Clipper South?	gas		Shell	2005		350bn cf		
*Cutter	gas	SNS	Shell	2005			platform	
Dalmore	oil	30/29b	Tuscan Energy	2005	7.5mn b (35mn STB)		extended reach drilling	
Ettrick?	oil	20/2a	Shell	2005	35mn b		FPSO or subsea	
*Fiddich (ETAP III)?	gas/oil	CNS	BP	2005	5mn b (cond)	105bn cf	2-well tieback to Marnock	2,000 b/d cond (06), 40mn cf/d (05/6)
*Gadwall South	oil	21/19	Venture	Apr-05	6.6mn b (7.3mn boe)	3.5bn cf	1 subsea to Kittiwake	
*Glenelg	gas/cond	29/4d	Total	3Q2005	15mn b (cond)	100bn cf	high dev ERW from Elgin	12,000 b/d (cond) + gas
*Horne and Wren	gas	53/03c	Tullow	Jun-05		64bn cf	2 horiz, NNM via Thames	90mn cf/d (05)
Jacqui?	oil/gas	30/13	ConocoPhillips	2005	10mn b	70bn cf	subsea to Judy	10,000 b/d (05), 50mn cf/d (05)
J4/Johnston?	oil/gas	SNS	Caledonia EU	2005			to Johnston manifold	
Magnus NW?	oil	211/7a	BP	2005	10mn b		ERD	
Monroe	gas	44/17b	Gaz de France	2005		82bn cf	NNM plat	
Nevis Centr'l(Ness)	oil/gas	ExxonMobil	2005	9mn b		subsea		
*Pict	oil/gas	21/23b	Petro-Canada	Jun-05	15.3mn b		subsea to Triton FPSO	10,000 boe/d (3 years)
*Rhum	gas/cond	3/29a	BP	Oct-05	9.4mn b (cond)	780bn cf	3 subsea tbk 44km to Bruce	300mn cf/d (16 years)
*Saturn-Atlas/Hyperion/ Rhea	gas	48/10b, 48/10a	ConocoPhillips	4Q2005		240bn cf	platform via LOGGS	170mn cf/d (06)
Onstream 2006								
*Blane	oil	30/3a	Paladin	end-2006	21.7mn b	7bn cf	Subsea tieback to Ula	15,000 b/d, 6-10mn cf/d (Ph1)
Brenda (East and West)	oil	15/25b	Oilexco	3Q2006	37mn b		4 horiz to Balmoral/Donan	24,100 b/d
*Brodgar & Callanish	gas/oil	21/03a, 15/29b, 21/4	ConocoPhillips	2006	40mn b+20mn b (cnd)	175bn cf	s'sea to new Britannia facils	60k boe, 35,000 b/d, 200mn cf/d
*Buzzard	oil	19/5, 19/10, 20/1, 20/6	Nexen	end-2006	460mn b	39bn cf	three steel platforms	200k boe, 180,000 b/d (07/8)
Captain C	hvy oil		Chevron	2Q2006			2 subsea to Captain A	
Cavendish Area +East	gas	43/19a	RWE-DEA	Oct-06		175bn cf	subsea to Trent	51mn cf/d (2006) £125mn
Chestnut PhII	oil/gas	block 22/2a	Venture	2006	16.1mn b		subsea	18,000 b/d
Curlew C	oil/gas	block 29/7	Shell	2006	17.9mn b	38bn cf	subsea to Curlew	
Donan?	oil/gas		Kerr-McGee	mid-2006				
Dumbarton?	oil	15/20a, 15/20b	Kerr-McGee	2006				
*Enoch/J1	oil/cond	16/13a	Paladin	end-2006	48.1mn b	16.1bn cf	subsea to Brae	7,725 b/d (07), 19mn cf/d (07)
*Farragon	oil/gas	16/28	BP	2006	20.7mn b	21bn cf	2 horiz wells via Cyrus	20,000 b/d
*Forvie North	gas/cond	Block 3/15	Total	2006	8mn b	170bn cf	subsea to Alwyn North	18,600 boe/d (06)
*Garrow	gas	42/25a	ATP	2006			2 wells NNM plat via Trent	60-100mn cf/d (Tors development)
Goosander/Wagtail/Whinchat	oil	block 21/12, 21/13a	Venture	3Q2006	16mn b++		subsea to Kittiwake	15,000 b/d
Hunter	gas	44/23a	Caledonia EU	2006		38bn cf	subsea tieback	16mn cf/d
Iris	oil	CNS	Tuscan Energy	2006	4.9mn b		subsea to?	
Kessog (SA)?	gas/cond	30/01c	BP	2006	60mn b (cond)	260bn cf	unmanned plat or subsea	
*Kilmar	gas	43/22a	ATP	2006			1 well NNM plat via Trent	60-100mn cf/d (Tors dev't)
Macallan?	gas/cond	CNS	ConocoPhillips	2006	5mn b (cond)	50bn cf	subsea tieback	
Mimas	gas	48/9a	RWE-DEA	4Q2006				
*Munro?	gas	44/17b	ConocoPhillips	2006?				
Perth	oil/gas	15/21b	Nexen	2006	33.5mn b	28bn cf	subsea to Scott	20,000 b/d (06)
Puffin?	oil/gas	29/4a, 5a, 9a, 10	Shell	2006	25mn b+40mn b (cnd)	260bn cf	wellh'd plat to Shearwater	18,000 b/d (08), 150mn cf/d (08)
Seagull	oil/gas	CNS	Shell	2006	16mn b	18bn cf	subsea to Audrey A/Loggs	
Tethys	gas	49/11b	RWE-DEA	4Q2006				
Topaz	gas	49/2a	Tullow	4Q2006		45bn cf	subsea	
Tors	gas	SNS	ATP	2006		109bn cf	Platform	part of Tors development

Table 3: North Sea fields onstream in 2004 and beyond

continued overleaf...

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
*Tweedsmuir	oil/gas	21/1aN	Talisman	4Q2006	61.7mn b	35bn cf	4 subsea via Piper B	30k boe, 40,000 b/d (07)
*Wood (SA)	oil/gas	22/18	Paladin	late 2006	15mn boe		1 subsea to Montrose	5,000 b/d, 21mn cf/d (07)
Onstream 2007+								
Babbage	gas	48/2a	Caledonia EU	2007		85bn cf	subsea to Johnston	
Barbara?	gas/cond	block 23/11	Dana	2007	4mn b (liquids)	120bn cf	tieback to ETAP or Everest	
Bardolino	oil	block 22/13a	Shell	2007			via Howe	
Blythe	gas	48/22a, 48/23a	Tullow	2007			via Hewett	
Chiswick	gas	49/3a	Centrica	2007		120bn cf	platform	
Curlew A -D	oil	block 29/7	Shell	2007	20mn boe		subsea to Curlew	
Don redev. W,SE (SA)	oil	211/18a	BP	2007	35mn b	35bn cf	subsea tieback to Don	
Devenick	oil	9/28a, 9/29b	BP	2008	123mn boe	480bn cf	subsea to new Harding plat	
Fyne/Dandy	oil	21/28a	Agip	2007	39mn b		FPSO?	
Gunn	gas		Caledonia EU	2007		17bn cf		
*Harding area gas	gas	9/23b	BP	2008			tiebacks to Harding platform	
Jill & Julia (SA)	oil/gas	30/7a	ConocoPhillips	2007			subsea tieback	
Kepler (ex Cavendish East)	gas		RWE-DEA	4Q2007			tieback to Cavendish	
Maria Terrace & Maria Horst	oil	16/2a, 16/29a	BG	2007+	65mn b		tieback to Armada	tested at 6,720 b/d
Melville	oil	210/24a-10	Amerada Hess	2007/8	110mn b		subsea to Hudson	
Orca and Minkie	gas	44/24a, 29b, 30	RWE-Dea	2008		282bn cf	wellh'd platform to D/15-FA	72mn cf/d (03)
Rita	gas		Caledonia EU	2007		58bn cf		
Rivers Hodder/Crossans	gas	110/7a	Burlington	2007	49,000 b (cond)	350-400bn cf	to NNM platform on Calder	80mn cf/d (06)
Rivers2 Crossans/Darwen	gas	110/2b, 110/7a	Burlington	2007		120bn cf		
Venture	gas	49/12a	ConocoPhillips	2007+		50bn cf	subsea tieback	
Possible develpments								
Acorn		29/8a, 29/8b	Venture					
Affleck?	oil/gas	30/19a	Kerr-McGee					
Alder?	gas/cond	15/29a	Chevron		30mn b (liquids)	250bn cf	subsea tieback	
Alwyn North Trias			Total					
Amy and Argo area	gas	48/10b,48/9a	ConocoPhillips			370bn cf	platform	
Anglia	gas							
Ani			Shell				subsea tieback	
Appleton area	gas/cond	20/11bN, 20/12bN	Venture		40mn b	60bn cf		
Arbroath/Montrose	oil	22/17, 18	BP				poss comp platform	
Auk North	oil	30/16	Shell		25-30mn b		subsea to Auk	
Bedevere	gas	48/14	ExxonMobil			100bn cf	ERD	40mn cf/d (04)
Beechnut	oil/gas	29/9a-s, 29/9b	Venture				subsea tieback or FPSO	20,000 b/d
Bennachie	oil	21/15a, 15b	Shell		15mn b		subsea to Forties or Nelson	10,000 b/d
Beta (UK)	gas	44/24a	Consort			75bn cf	wellh'd platform to Orca	35mn cf/d (04)
Block 15/23	cond	15/23d	BG					
Block 16/26	oil	16/26a	BP				platform	
Bressay	hvy oil	3/28a	Chevron		200mn b			
Brigitte	gas		BG					
Centurion		29/6a	Venture					
Christian and Bligh		21/20a	Venture		7.1mn boe		tieback to Mallard	4-5,000 b/d
Dolphin		22/18	BP					
Ensign	gas	48/14	Centrica				platform	
Flyndre			Total				subsea tieback	
Glenn			BP				subsea tieback	
Halley discoveries		30/11bS, 30/12bS	Venture					
Johnston Gamma			BHP				ERW	
Josephine	oil/gas	30/13	ConocoPhillips		30mn boe	95bn cf	subsea to Judy	8,000 b/d , 50mn cf/d
Kate/Turnstone	oil/gas	22/23b, 28a	BP?		73mn boe	20bn cf	subsea	20,000 b/d , 15mn cf/d
Kildrummy (Lucy)	oil	15/12b, 15/17	Talisman		40mn b	25mn boe	subsea tieback to Piper B	
Lennox West			Burlington				subsea	
Mandarin	oil	22/23b, 22/28d, 22/28a	Shell					
Marcel/Bravo								
Mariner	hvy oil	9/11a	Chevron		100mn b		project on hold	
Mirren	oil/gas	22/25b	Shell				subsea	
Nevis Far North			ExxonMobil				ERW	
Peik UK	oil/gas	9/15a	Total		20mn b	350bn cf	subsea to Beryl A	9,000 b/d , 110mn cf/d
Pilot	oil	21/27	Total		77mn b		floater?	
Quasimodo (HT/HP)	gas							
R Block	oil	15/27	ConocoPhillips					
Ramsay	gas	53/5b	BP			75bn cf	ERW from Davy?	
Skye	oil	211/23a, 23c	Shell		20mn b		subsea to Dunlin	11,000 b/d
Solan/Str'thm're (SA)	oil/gas	204/30	Amerada Hess				FPSO	40,000 b/d
Suilven	oil	204/19	BP					
Thebe	gas	49/22	ConocoPhillips			74bn cf	with ECA Phase II	35mn cf/d
Tornedo	oil	22/23b, 28a, 28c	Shell		30mn b			20,000 b/d
Wissey	gas	53/04	Tullow				subsea	
York	gas	47/3a	Amerada Hess		test 24.7mn cf/d	200bn cf		
Key discoveries								
close to Buchan	oil/gas	21/1a-20	Talisman		10-40mn b in place			
close to Brigantine	gas	49/20a, 49/20b	Shell					
West Franklin	gas/cond	29/5b	Total		test 1mn cm/d,2kb/d cnd			
close to Buzzard	oil		Edinburgh O&G		30mn b			
Melville extension	oil	210/24a-10	Amerada Hess		oil discovery Apr-05			
Montrose North	oil		Paladin				via Montrose	
5 miles from Camelot	gas	53/2	ExxonMobil		65mn cf/d on test			
Rosebank/Lochnagar	oil/gas	213/27-1Z	Chevron		400-500mn b			
Opal	gas	43/25a-2W	Gaz de France				within Caister Murdock CMS	
Phoenix	oil	22/12a	Shell		60-ft oil column		via Howe	
NETHERLANDS onstream 2004								
D-12	gas	D12a	Wintershall	2004			platform (2 wells)	
L-06d	gas	L/6	NAM/ATP	2004				
Q5-A	gas	Q5	Wintershall	2004		21bn cf	subsea to Q8-B	2005-2009
A & B quadrant	gas	A12a, A18a, B13a	Unocal	2005		400bn cf	platform	
De Ruyter	oil	P10, P11b	Petro-Canada	1H2007			gravity platform and deck	25-30 kb/d (2007)
D12-A (west)	gas	D12a	Wintershall					
D18-FA	gas	D18	Gaz de France					
F16-A	gas	F16/E18	Wintershall	Jan-06		450bn cf	1 steel platform, 5 wells	init prodn 150mn cf/d
G14A & B	gas	G14a	Gaz de France	2005			platform +subsea	
G16-FA	gas	G16a	Gaz de France	2005		220bn cf	platform	
G17	gas	G17	Gaz de France	2005?				
K/2-A	gas	K/2b	Gaz de France	2005		250bn cf	platform	
K4b/5a	gas	K/5a	Total					
K-17-FA	gas	K-17	NAM					
L02-FB	gas	L02	NAM					
L04-G	gas	L04a	TotalFinaElf	2005		100bn cf	platform	
L133 -FF	gas	L13	NAM					
MO6-FB	gas	N07a	NAM					
NO7-FA	gas	Noord-Friesland	NAM					

Table 3: North Sea fields onstream in 2004 and beyond

continued overleaf...

Field name	Oil/gas	Block no.	Operator	Start-up	Oil resvs	Gas resvs	Prod. system	Peak prod. (yr)
Probable dev's								
K/5-Fe	gas	K/5	Total	2002		80bn cf	platform	
K/7-FB	gas	K/7	NAM	2003		150bn cf	platform	
K/15-FE	gas	K/15	NAM	2003		30bn cf	platform	
K15-FJ	gas	K/15	NAM	2004		40bn cf	platform	
L/2-FB	gas	L/2	NAM	2003		85bn cf	platform	
L/9-6	gas	L/9A, L/9B	NAM	2003		100bn cf	platform	
Minke (Neth)	gas	M/7	NAM	2003		100bn cf	platform	
Orca (Neth)	gas	D/15, D/18A	NAM	2003		104bn cf	platform	45mn cf/d (2001)
Q/1-A	gas	Q/1	Conoco	2004		400bn cf		40mn cf/d (2002)
Key discoveries								
K15	gas	K/15	Shell, ExxonMobil			300bn cf		
NORWAY onstream 2004								
*Kvitebjorn	gas/cond	34/11	Statoil	Sep-04	190mn b (cond)	55bn cm	PDQ platform	20mn cm/d, 62,000 b/d (cond)
*Mikkel	gas/cond	6407/6, 6407/5	Statoil	Feb-04	40mn b (cond)	28bn cm	4 subsea to Asgard B	30,000 b/d
*Skirne/Byggve	gas/cond	block 25/5	Total	Mar-04	10.7mn b (cond)	6.7bn cm	2 subsea to Heimdal	6,900 b/d, 150mn cf/d
Sleipner Alpha North	gas/cond	block 15/6	Statoil	Oct-04	32mn b (cond)	13bn cm	subsea to Sleipner T	
Valhall water inject	oil	block 2/8, 2/11	BP	Jan-04	additional 150mn b		15-well plat to inj 210,000 b/d	
Onstream 2005								
*Asgard Q	oil			2005				
Ekofisk Growth	oil/gas	block 2/4	Phillips	2005	156mn boe		wellhead plat +mods	
Gulltopp (ex Dolly)	oil	33/2	Statoil	Jul-05	25mn b	500mn cm	ERW from Gullfaks A plat	NKr300mn
*Kristin (Halten Bank W)	gas/cond	6406/2-3, 11	Statoil	Oct-05	220mn b cond	34.9bn cm	12subsea to FPU to Asgard	126,000 b/d (cond), 15mn cm/d
Lerke	oil	6608/10	Statoil	2005			subsea to Norne	
Njord Gas	gas	6407/7,10	Norsk Hydro	2005		10bn cm	platform modifications	
Ole/Dole	oil	33/12	Statoil	2005	13.2mn b	1.1bn cm	subsea Statfjord/Oseberg	
Oseberg J South	oil/gas		Norsk Hydro	Jul-05	24mn b	0.5bn cm	2 producers to Oseberg S	25,000 b/d
Oseberg W Flank (Tune ph2)		oil/gas	block 30/6	Norsk Hydro	Oct-05	35mn b	5.6bn cm	
Tommeliten Alpha	oil/gas	block 1/9	Phillips	2005	16mn b	3bn cm	subsea to Ekofisk?	1 subsea via Oseberg
Topaz	oil	34/10	Statoil	Feb-05	10mn b		ERW from Gullfaks C	
Troll A compression	gas	block 31/6	Statoil	2005			additional compression	
Visund Gas	gas	block 34/8	Norsk Hydro	2005	4.7mn t NGLs	50.5bn cm	via Visund F wells	
Onstream 2006								
Fram East	oil/gas	35/11	Norsk Hydro	Oct-06	60mn b	2.9bn cm	4 producers to Troll C	11,000 boe/d
Freja-Mjolner	oil	block 2/12	Amerada Hess	2007	18.2mn b	0.6bn cm	subsea to Valhall or Arne	
Gjoa	oil/gas	35/9, 36/7	Norsk Hydro	mid-2006	41mn b	29.4bn cm	subsea to Troll	
Goliat	oil	7122/7 (Barents Sea)	Agip	2006	50mn b		FPSO	
Gudrun	gas/cond	block 15/2, 15/3	Statoil	2006	87mn b (cond)	15.6bn cm	NNM plat to Sleipner/Brae	
Heimdal West	oil/gas	block 24/6, 25/4	Marathon	2006			FPSO or tiebk Heimdal	
Skinfaks	oil	block 33/12	Statoil	Nov-06	15.7mn b (31mn boe)	1bn cm	8 subsea to Gullfaks C	
*Snoehvit+ others	gas/cond	7120/5,6,7,8,9, 7121/4,5,7	Statoil	2006	114mn b (cond)	151bn cm	subsea 160km to Melkoya	20.8mn cm/d
Tordis extended recovery	oil		Statoil	2006	+35mn b		subsea separation	
Urd (ex Svale/Staer)	oil	6608/10	Statoil	2006	50mn b and 16mn b	0.2bn cm, 0.1bn cm	8 subsea via Norne	70,000 b/d NKr3.6bn
Varg South	oil/gas	block 15/12	Pertra (PGS)	2006	25-30mn b	4bn cm	ERD from Varg + subs	
Onstream 2007								
Alvheim development	oil/gas	24/6, 25/4	Marathon	early 2007	152mn b (180mn boe)	4.9bn cm	FPSO + drill centres	80,000 b/d, 0.9mn cm/d
Inc Kneler, Boa, Kameleon							total project 250mn boe	
Falk/Linerle	oil	6608/11	Statoil	2007	6.3mn b		subsea to Norne	
Hamsun (Nr Alvheim)	oil/gas	36792	Marathon Oil	early 2007			tieback to Alvheim	
*Ormen Lange	gas/cond	6305/4,5,7,8	Norsk Hydro	2007	182mn b (cond)	397bn cm	processing platform	50mn cm/d, 20 year plateau
Oseberg Delta	gas/cond	block 30/9, 30/8	Norsk Hydro	Oct-07	17mn b (cond)	8bn cm	2 subsea via Oseberg D	5mn cm/d. In production until 2014
Statfjord late life	oil/gas		Statoil	3Q2007	+25mn b, 60mn b (cnd)	+32bn cm	Tampen Link (gas)	
Vilje (ex Klegg)	oil	block 25/4	Norsk Hydro	Feb-07	50mn b	0.4bn cm	2 subsea to Alvheim	35,000 b/d
Volve	oil/gas	block 15/9	Statoil	2Q2007	70mn b, 0.5mn t (NGLs)		1.5bn cm	jackup and FSO 50,000 b/d (4-5 years)
Onstream 2008								
Dagny	gas/cond	blocks 15/6 and 15/5	Statoil	2008	7.5mn b cond	3.8bn cm	subsea via Sleipner A	
Freja-Mjolner	oil	block 2/12	Amerada Hess	2008	18.2mn b	0.6bn cm	subsea to Valhall or Arne	
Gjoa	oil/gas	35/9, 36/7		2008	50mn b	25bn cm		
Goliat	oil	7122/7	Agip	2008	50mn b		FPSO or subsea	
Gudrun	gas/cond	15/3, 15/2	Statoil	2008	91.2mn b oil/cond	7.7bn cm	platform to Sleipner	
Lavrans	gas/cond	6406/2	Statoil	2008	24.5mn b cond	13.9bn cm	subsea to Kristin	
?Peik	gas/cond	24-Jun	Total		7.5mn b	5.3bn cm	subsea	
Trym	gas/cond	block 3/7,3/8	Norske Shell	2008	5mn b (cond)	3.3bn cm	subsea to Arne South	
Onstream 2009								
Tyrihans N &S	oil/gas	6407/1, 6406/3	Statoil	2009	182mn b oil/cond	34.8bn cm	subsea to Kristin & Karstoe	
Valemon	gas/cond	34/10, 34/11	Statoil		8.2mn b cond	12.8bn cm	subsea to Kvitebjorn	
Valhall Redevelopment	oil/gas	block 2/8, 2/11	BP	3Q2009			process/accom platform	150,000 b/d, 5mn cm/d
Onstream 2010								
Skarv	gas/cond	6507/3,5,6	BP	2010	92mn b liquids	38bn cm	to Karstoe, Tampen link	16mn cm/d, 100,000 b/d
Idun (ex Fangst)	gas	6507/3	Statoil	2010	1mn b, 1.3mn t NGLs	13.5bn cm	to Karstoe, Tampen link	
Key discoveries								
Astero	oil	35/11-13	Hydro	May-05	tested 3,150 b/d		via Fram to Troll C	
Lerke	oil	6608/10	Statoil					
Onyx South West	gas	6406/9	Shell	May-05		60bn cm (NPD)		
Hvitveis	gas	6706/6	ExxonMobil					
Tofte	gas/cond		Statoil	Jan-04	10mn b (cond)	5bn cm	tieback to Kristin	NKr655mn
Verdandi	gas	block 16/1	Statoil					
DENMARK onstream 2004								
Dan FG	gas	5505/07	Maersk	2004			gas processing platform	6.8mn cm/d
Halfdan III	oil/gas	5505/13	Maersk	2004	486mn b	8.6bn cm	two jackets + bridge	100,000 b/d
Siri East Segment	oil	5605/13	DONG	2004	15mn b		subsea to Siri	
Stine	oil		Paladin	2004				
2005 and later								
Adda	oil/gas	5504/8	Maersk	2010	6mn b	1bn cm	subsea or NNM to Tyra	
Alma	oil/gas	5505/17	Maersk	2009	6mn b	1bn cm	platform to Dan F	4,000 b/d, 22mn cf/d
Amalie	gas/cond	5604/26	DONG	eval	13mn b cond	3bn cm	platform to South Arne	7,000 b/d, 42mn cf/d
Boje	oil	5504/7	Maersk	2011	5mn b		subsea to Roar/Valdemar	
Elly	oil/gas	5504/6a	Maersk	2009	6mn b	1bn cm	NNM platform to Tyra	
Freja-Gert	oil	5603/27, 28	Maersk	??	7mn b	1bn cm	subsea	
Hejre	oil	5603/28	ConocoPhillips	2007			platform to South Arne	
*Valdemar Extension	oil/gas	5504/7, 5504/1	Maersk	2005			platform + pipeline	
Key discoveries								
Sofie-1	oil	20km NE of Siri	Paladin	2004			tieback to Siri	

Table 3: North Sea fields onstream in 2004 and beyond

Norway races to develop new fields

Photo: Øyvind Hagen/Statoil

Norway is leading the charge to tap more North Sea resources as a raft of new field developments have come forward in the last few months to reinforce the country's position as the region's primary offshore producer, reports John Bradbury.

This year the Norwegian Petroleum Directorate (NPD) estimates that there are still 12.9bn cm of oil equivalents in recoverable resources to be tapped – according to the NPD's 2005 resource report.

Coupled with high levels of exploration activity and a number of new entrants to the market, the Norwegian petroleum sector is still buoyant, based on forthcoming field developments, a new 19th licensing round – announced in June, offering 64 Barents Sea and Norwegian Sea blocks – and the prospect of future cooperation with Russia over oil and gas potential in the far northern regions of both countries.

Denmark has at least eight projects underway, involving either new or existing fields and a sweep through the Dutch North Sea indicates at least five new projects. Nevertheless, Norway is where most activity is currently taking place.

The largest of Norway's headline projects is due to see first oil in 2007, when the Marathon-operated Alvheim development – comprising the Boa, Kneler and Kameleon discoveries west of Heimdal – comes onstream.

Marathon and Lundin Petroleum's Hamsun oil and gas discovery – drilled March to April 2004 – is also a contender for inclusion in Alvheim, while, earlier this year, the project partners also agreed to include Norsk Hydro's Vilje discovery – previously known as Klegg – in the project, taking total estimated reserves to 250mn boe.

Alvheim will be exploited by converting the multi-service shuttle tanker (MST) *Odin* into a floating production storage and offloading vessel (FPSO) which will produce from five drill centres. Vetco Aibel won a $350mn contract earlier this year for conversion of the *Odin* to provide oil and gas processing equipment, including design and construction of production separators, gas compression and dehydration, water treatment and power generation equipment. Topsides units are under construction by Vetco Aibel in Haugesund, Norway, while the ship – built with a double hull in 2001 by Izar in Spain, and bought by Marathon from Statoil – is currently at Keppel shipyards, Singapore to expand storage capacity from 530,000 to 560,000 barrels of oil.

Advanced Production Loading (APL) snared its biggest ever contract in November 2004 when Alvheim partners selected it to supply a submerged turret mooring system for the *Odin* MST in a NKr400mn deal.

Development drilling was due to commence this July, after Marathon contracted Odfjell Drilling's *Deepsea Bergen* semi-submersible for $65mn (NKr460mn) for 10 firm 60-day wells on Alvheim plus options for five further wells.

Procurement recently started for Statoil's Tyrihan's subsea project in the Norwegian Sea, which will export gas via the newly-installed Kristin semi-submersible platform and Åsgard Transport line to the Kårstø gas terminal, near Stavanger. Oil and condensate will be exported via the Asgard C production ship and shuttle tankers, under a plan for development and operation (PDO) submitted in July to Norway's Ministry of Petroleum and Energy (MPE). Tyrihans is 22 miles (35 km) south-east of Kristin, in a water depth of 1,000 ft (300 metres), but is not due onstream until 2009, when processing capacity will become available on

Kristin's production semi-submersible. Five subsea templates and 12 wells are indicated in the PDO – nine producers, two for gas injection plus a water injector.

Commencing procurement now allows Statoil to secure long lead items, including pipeline steel. German manufacturer Butting won a NKr300mn deal for supplying export line steel, which is due for delivery December 2006, ready for the 2007 pipeline installation season.

The *Transocean Arctic* has been contracted for three years' development drilling at Tyrihans, worth NKr2bn, and NKr5bn including completion work.

Overall, Tyrihans, with recoverable reserves estimated at 182mn barrels of oil and condensate, plus 34.8bn cm of gas, is costing NKr14mn to develop. It represents a technology stretch target for Statoil, with a heated 26.8 mile (43 km) pipeline – for flow assurance – being designed to export production back to Kristin.

'This field calls for extensive technology development, but the work still needing to be done is felt to be at an acceptable level,' stated Ståle Gjersvold, Tyrihans' Project Manager.

Another recent discovery, Tofte, will form a further phase of the Kristin project after being discovered while drilling the first Kristin development well in January 2004. It is scheduled to be tapped for NKr655mn to recover 5bn cm of gas and 10mn barrels of condensate.

Extending oil recovery is a clearly emerging theme on the Norwegian Continental Shelf, where a boosting plan has been approved for the Tordis field. Here, Statoil has awarded Kongsberg FMC a letter of intent worth NKr625mn for delivering subsea separation systems at the field, in the first full-scale adoption of subsea separation technology according to Hans Kristiansen, the Project Manager. Tordis is already tied back subsea to the Gullfaks C platform, and phase one of an extended recovery project will see Gullfaks C converted for lower production pressure operation. This should produce an additional 16mn barrels in 2006 and a second phase due onstream October 2007, featuring the subsea separation system and pumps, will recover a further 19mn barrels. Overall, Tordis recovery should be boosted from 45% to 55%, equalling 35mn barrels of additional oil.

Figure 1: A submerged turret loading and mooring system supplied by APL will hook up the Alvheim FPSO to subsea wells *Source: Marathon Oil*

Since February this year, the Topaz discovery 1.8 miles (3 km) north-east of Gullfaks has been producing as a long distance tieback to Gullfaks C, after discovery in November 2004 with the 34/10-48S well in water depth of 711 ft (217 m).

Also, Gullfaks A was due to host production from the Gulltopp discovery – formerly known as Dolly – commencing July 2005 – as a single extended reach well with 32,800 ft (10,000 metres) total length. Gulltopp's estimated 25mn barrels of oil and 500mn cm of gas was discovered in block 33/2 in 2004 and will

A second chance for Statfjord

New plans for development and operation (PDO) of the Statfjord field and an associated Tampen link pipeline received approval from the Norwegian Storting (parliament) in June this year.

It involves depressurising one of Norway's oldest offshore fields and turning it into a gas-production centre.

Partners in the field have a green light for a $2.43bn (NKr16bn) investment programme which is designed to enhance oil and gas recovery. Statfjord – discovered 1974 and onstream by 1979, via three installations, A, B and C – is to be converted from oil handling with associated gas to gas handling with associated oil. Statfjord A, B and C will undergo major re-engineering – a cheaper option than installing new platforms according to the operator Statoil – involving 3mn man-hours of offshore work over four years, plus another 3mn hours of onshore engineering.

The project is being undertaken in two phases. Phase one, commencing this autumn (2005) until the second half of 2007, involves converting 70 out of the field's 124 production wells to gas production and sand control, so as to produce low pressure gas from the Statfjord reservoirs.

'Today we use gas and water injection to maintain reservoir pressure at around 320 bar. By stopping the injection, the reservoir pressure should slip below bubble point [the point at which associated gas dissolved in oil under pressure bubbles out] to around 120 bar,' explained Statoil spokeswoman Kjersti Tvedt Morstøl.

It also means upgrading topsides to meet more recent and stringent health, safety and environmental standards. Phase two, from autumn 2007 to the end of 2009, will see topsides production facilities converted for low pressure oil and gas production.

Approval has also been given by the Norwegian government for the 32-inch diameter Tampen Link gas pipeline – connecting Statfjord B via a 14.4-mile (23.1 km) pipeline to the UK Brent area and the Far North Liquids and Gas System (FLAGS) pipeline to the St Fergus terminal in Scotland. This is due for installation in autumn 2006.

About 60% of the project cost is due to platform modifications, 30% for drilling and 10% for the Tampen link.

All this investment should see Statfjord oil recovery raised to 70% and gas to 75%, Statoil hopes, with the overall prize being additional recovery of up to 1,129bn cf (32bn cm) of gas, 25mn barrels of oil and 60mn barrels of condensate. Statfjord's production life should also be extended to at least 2018 (Statoil originally envisaged production continuing until 2010).

Aker Kvaerner, Vetco Aibel and Smedvig have together already collected contracts worth $468mn (NKr3.1bn) in related project work.

be exploited for around NKr300mn.

Gullfaks is part of the jigsaw for other developments, including the Skinfaks and Rimfaks discoveries. Both were approved by the MPE for development and operation in February 2005. Skinfaks, proven in 2002, involves up to eight planned production wells. It is due onstream in November 2006, with the *Transocean Leader* contracted to drill the first three production wells under a NKr550mn, 225-day contract commencing this autumn. Separately, FMC Kongsberg was selected to supply five xmas trees, a subsea template and satellite structure plus two manifolds for Skinfaks under another NKr500mn Statoil award. Rimfaks has been tied back to Gullfaks A since 2000, but the combined PDO suggests further Rimfaks wells in the future. Overall, the estimated development cost is NKr3.4bn to tap 70mn boe, but an initial six-month pilot project is designed to exploit only 3mn barrels.

Approved for development in April this year, Volve is a new stand-alone Statoil development set to see first production in spring 2007 using a Maersk jack-up rig for processing and the *Navion Saga* as a storage tanker. Volve is costing NKr7bn to tap 70mn barrels of oil and 1.5bn cm of gas – which will be exported to Sleipner A – with plateau production of 50,000 b/d of oil and an expected lifespan between four and five years. Already, Stolt Offshore has been selected for installation of infield and export lines, while NKT Flexibles is supplying the lines. APL has also been chosen to supply a submerged turret loading system. Development will feature three production, three water injection and two water production wells.

Statoil's Visund field is receiving further attention with a gas redevelopment project. Two 600-tonne gas export and compressions modules, MO1 and MO2, were installed by Heerema this summer, allowing the start of gas exports by October. Associated with this, a 23.7 miles (38 km), 20-inch gas line has been installed to export gas from the Visund production semi-submersible platform to the Kvitebjorn export line running to the Kollsnes process plant near Bergen via Troll.

Still with Statoil, the NKr3.6bn Norne Satellites development, now known as Urd, comprises the Svale and Staer discoveries, 6.25 miles (10 km) and 3.1 miles (5 km) north of the Norne production ship in the Norwegian Sea. A PDO for the fields received MPE approval July 2004, involving eight wells in three subsea templates – two for Svale and one for Staer. This is additional to Statoil's Norne extension programme, which saw FMC Kongsberg awarded a NKr170mn contract to supply a new four-slot subsea template, designated K, and two xmas trees to recover an additional 10mn barrels of oil commencing production in autumn 2006.

Norsk Hydro is not being left behind in the race to exploit remaining Norwegian reservoirs. Last November, Hydro submitted a PDO for exporting gas from the Njord A floating production unit into the Åsgard transport line as part of a NKr1.6bn field conversion to gas export, producing 2.2 bn cm/y. This redevelopment with new production wells will see the application of cheaper, slim-hole through-tubing

New North Sea fields for 2005–2006

There will be 32 new fields coming onstream on the UKCS in the next two years during 2005 and 2006 a new economic report indicates, writes *John Bradbury*. All the developments are forecast in the UKOOA (United Kingdom Offshore Operators Association) Economic Report for 2005, which identifies 16 field developments scheduled to come onstream this year and another 16 in 2006.

Most are subsea developments – tiebacks to existing infrastructure – in either the central or southern North Sea, the new UKOOA report indicates. However, a number of platform-based projects are also indicated, offering opportunities for fabrication contractors.

Most fields are small in size – less than 50mn barrels of oil – compared to a decade ago: Paul Dymond, Operations Director of UKOOA, pointed out that a half a percentage point rise in recovery from the huge Forties oil field would be significantly more than any of the new field developments coming onstream in the next couple of years – with the exception of Nexen's forthcoming development of the 460mn barrel Buzzard oil field. Buzzard is due onstream in 2006, but most projects today are between 25mn and 50mn barrels in size. The latest UKOOA field development survey cites only one project – Talisman Energy's Tweedsmuir oil – as being above that, at 61.7mn barrels of recoverable oil.

Other projects include Nexen's 33.5mn barrel Perth oil and gas project in the central North Sea. The next largest deposit scheduled between now and 2006 is BP's Farragon discovery, with 20.7mn barrels of recoverable oil.

The biggest gas development forecast for the next couple of years is also BP's Farragon project, with 22.1bn cm (780.39bn cf) of recoverable gas reserves. Next largest is Total's Forvie North gas and condensate project, with 4.8bn cm (169.49bn cf) of estimated recoverable gas, while the ATP-operated Tors development is indicated to have 3.1bn cm (109.46bn cf).

Continuing an upbeat outlook for the North Sea, UKOOA said exploration activity in the UK sector of the North Sea rose by 40% in 2004, when there were 63 exploration and appraisal wells drilled, including sidetracks. This was the highest level for seven years since 1998. For 2005, UKOOA expects the number of E&A (exploration and appraisal) wells to increase by a further 10%, suggesting a 2005 total of around 70 E&A wells.

Investment to rise

Investment in the UK sector of the North Sea is set to remain steady, based on returns from North Sea operators to a November 2004 survey carried out by the UK's Department of Trade and Industry: 'Total expenditure including exploration and appraisal, investment in new production and operations is projected to rise sharply, exceeding £9bn in 2005.'

That figure compares with declines in capital investment in new and producing fields during 2002 and 2003. However, UKOOA said: 'Investor sentiment improved during 2004 and investment is expected to rise from £3.3bn to £3.8bn in 2005.'

UKOOA's report – *Energising Future Generations* – points to remaining UK reserves of up to 28bn barrels of oil and gas, offering substantial development possibilities for the future, 'provided the industry remains internationally competitive and can sustain investment at current levels'.

The industry spent over £8bn in 2004, and investment is forecast to increase this year. 'Current investment will halve the rate of production decline to around 6–7% per annum over the next five years, but challenges remain if the industry is to continue to slow the rate of decline over the long term,' states UKOOA.

'If the UK oil and gas industry can sustain investment at the current rate then we could still be producing 65% of our total oil requirements and a quarter of our gas requirements in 2020,' commented Malcolm Webb, Chief Executive of UKOOA.

drilling technology, to boost recovery from 20% to 30%. It also requires installation of a 25-mile (40-km) 12-inch export line from Njord A to Åsgard – awarded to Stolt Offshore in a $50mn deal. From Åsgard, gas will go to the Kårstø terminal. Engineering is already underway by Stolt, for pipeline trenching, rock dumping and tie-ins.

Njord gas is one of seven Hydro-operated Norwegian shelf projects due onstream 2005–2007. Apart from Ormen Lange, Hydro also has Oseberg South J and Oseberg West Flank due onstream this year; new drilling at Oseberg East and the Fram Øst development, which are both due by the end of 2006; Vilje is due onstream 2007 within Alvheim, then Njord gas and Ormen Lange by 2007.

Fram Øst, due onstream at the end of 2006, is forecast to produce 11,000 boe/d via four production and two water injection wells tied back 11.8 miles (19 km) south to Troll C. Aker Kvaerner Offshore Partners, under a NKr265mn engineering procurement and construction deal, has been contracted for the necessary Troll C modifications to connect up and process Fram Øst output.

Elsewhere, Hydro's Oseberg Delta project, a NKr1.8bn two-well development due onstream October 2007 as a subsea satellite to the Oseberg D platform, will recover an estimated 8bn cm of gas, plus 2.7bn cm of oil and condensate.

Delta is the latest of three Oseberg projects, after Oseberg South J came onstream in June; the Oseberg West Flank project, and a new Oseberg East drilling solution, due by the end of 2006.

Oseberg South J is a NKr1.6bn six-well satellite development 4.3 miles (7 km) south-west of Oseberg South, with two 8-inch production and water injection pipelines, plus two production and two water injection wells. Reserves are 24mn barrels of oil and 50bn cm of gas.

Oseberg West Flank, or Tune phase II, was due to go ahead with installation work this summer by Subsea 7 of a flowline, and umbilical – under a NKr260mn contract – and drilling of a single well. With 35mn barrels (5.4mn cm) of oil and 197bn cf (5.6bn cm) of gas, the satellite is 6.25 miles (10 km) from the Oseberg centre, and due onstream by October.

BP unveiled big plans for a NKr6.3bn redevelopment at its Valhall asset, featuring the use of power supply from shore to energise the field in the future. If approved, it will save 78 MW of offshore power generation from gas turbines. BP says this will make Valhall: 'One of the most environmentally-friendly fields offshore Norway.' Two FEED contracts have already been let to ABB and Nexans for voltage converters and

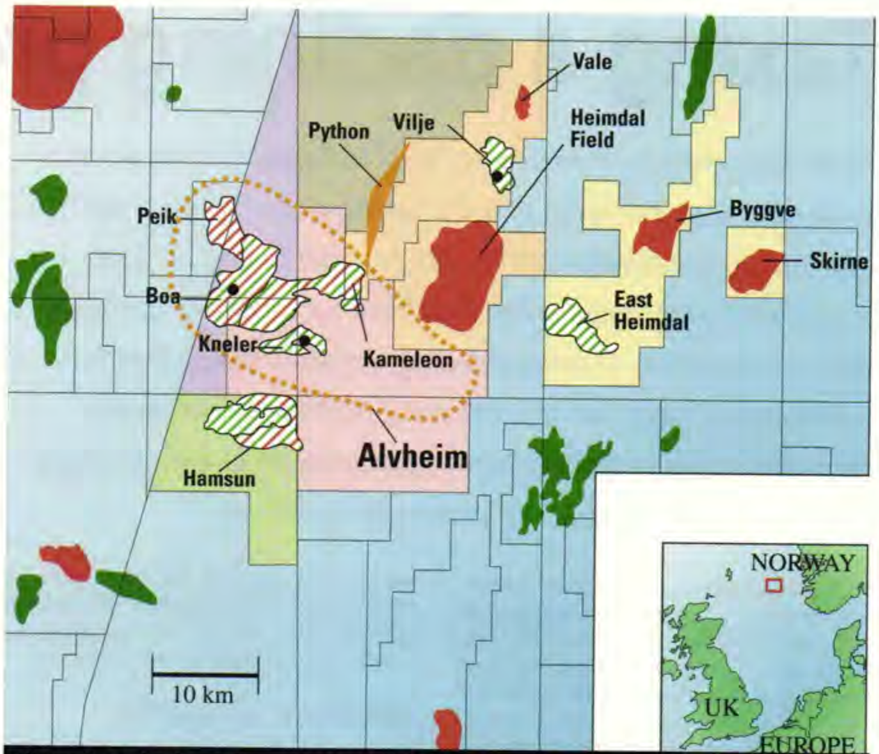

Figure 2: Production centre – Alvheim will form a new energy development hub west of the Heimdal field area offshore Norway *Source: Marathon Oil*

cabling from Lista to Valhall. The five-platform field centre will also see a new accommodation and production platform installed by 2009, enhancing process capacity to 150mn b/d of oil, 175mn cf/d of gas, and total liquid handling including water injection to 250,000 b/d. Potentially, these new facilities will extend Valhall's lifespan to 2050.

In June, Wood Group won a FEED contract for the project. BP says it will submit a PDO by 2Q2006.

In the Dutch sector, more gas developments are underway, including NAM and Shell's K-17-FA project. A spokesman for NAM/Shell Southern North Sea confirmed: 'We are currently working on the K17-FA,' but without furnishing further details.

Wintershall is developing its F16A discovery, and Gaz de France is progressing two more, G14 and G17. ATP Oil and Gas contracted Stolt Offshore to install a flowline and umbilical to tap a single well, L6, and tie it back 25 miles (40 km) to the G17 gas platform under a $17mn deal, while Petro-Canada expects its $399mn (300mn) De Ruyter project onstream in the first half of 2007, with peak production of 25,000 to 30,000 b/d of oil.

In the Danish North Sea, last December AP Møller sought approval from the Danish Energy Ministry (DEA) for a single development well on the Maersk-operated Dagmar field – first onstream in 1991 – to tap 3.5mn barrels of additional oil. Møller also plans to exploit the Bo area of the Valdemar field, after a summer 2004 appraisal well, Bo-2x '...demonstrated more favourable oil saturations and porosities in the Bo area than previous anticipated'. After re-interpretation of 3D seismic data, a new 10-slot wellhead platform development with pipelines to Roar has emerged, entailing six production wells and the possibility of four more to tap 24mn barrels of oil, and 3bn cm of gas. Bo is due onstream in 2007. Both projects are currently under consideration by DEA.

Future Danish developments operated by Maersk Oil and Gas include Adda in block 5504/8, discovered in 1977, which is due onstream 2010. Alma, in block 5505/7, discovered in 1990, and Elly gas, in 5604/6, discovered 1984, have both been approved for development and are due onstream in 2009. The Boje area, block 5504/7, is scheduled onstream 2011. No development plan has yet been listed for Maersk's 1984 Freja oil find in blocks 5503/27 and 28.

Development of Amalie, in block 5604/22 and 26 operated by DONG E&P is currently under consideration by the DEA after discovery in 1991.

At the Dan field, producing since 1972, Maersk gained approval earlier this year for six more wells in the north-eastern area. At Gorm, four new wells are planned, and possibly five more, to increase recovery under a £46mn (DKK 500mn project) – upgrades to field processing equipment are included in the plan. Gorm's first new well is to commence drilling this year.

Taxing a declining province

North Sea production has peaked. Although predicted for decades, most observers now agree that the turning point has been reached and the UK, will again become a net importer of gas, probably this year, and of oil by about 2008. Crucial to the successful management of this period of gradual decline, argues Dr Carole Nakhle,* *a petroleum analyst, will be getting the North Sea fiscal regime right. This needs to be based on an understanding of the advantages and disadvantages of past and present tax structures.*

This shortened version of her paper presents a qualitative assessment of the UK petroleum fiscal regime, based on a 'Survey of Opinions' solicited from key players in the UK oil sector, on the fiscal regime over the last 30 years. The survey was conducted between March 2002 and August 2003.

The 1975 fiscal package

From a government perspective, the 1975 fiscal package was justified as follows. The Royalty element gives oil companies the right to exploit the government-owned oil resource. The government receives a specified part of the production as a compensation for the depletion of its assets. The Petroleum Revenue Tax (PRT) element applies as a super-profits tax, aimed at capturing 'a share of the economic rent from oil activity' in the UKCS. The Corporation Tax (CT) element is imposed because all companies in the UK pay income tax and oil companies are no exception.

Consultant respondents argued that since oil was a new experience for the UK, the country had broadly to follow what other countries were doing. Royalty was a common instrument applied in other countries to oil production, albeit mainly to onshore fields.

PRT, unlike Royalty, provided for the deduction of all direct costs. Had Royalty applied to a more homogeneous cost base, the government wouldn't have needed the PRT. It was also argued that the reason for imposing PRT was that in the wake of the high oil prices in the 1970s, the government required a windfall tax on top of Royalty and CT.

However, the regime was not seen as sensitive enough to changes in oil prices. All respondents from the oil industry agreed that the 1975 package was unsatisfactory, mainly as the result of the imposition of Royalty and the high marginal tax take. The main limitation of the 1975 package was seen as its complication, which imposed administrative burdens.

Abolition of royalty

From a government perspective, since the Royalty did not allow the deduction of most costs, it could distort the investment decision, particularly with respect to marginal activities. Abolition of Royalty in 1983 was not believed to have generated a loss in revenue for the government.

All respondents commented that the imposition of Royalty on gross revenues rather than profits was not a desirable feature.

In terms of the effects of Royalty on early abandonment and marginal fields, divergent views emerged. About one-third of respondents agreed that Royalty leads to early abandonment. Government respondents expressed a contrary view, given the possibility of Royalty remission.

Industry opinion about the effects of Royalty abolition on the development of marginal fields diverged. Among 11 respondents, seven argued it encouraged the development of marginal fields. 'The improvements in the fiscal regime made in 1983 led to a material increase in development activity that lasted through the 1980s despite the rapid real decline in the oil price', said one respondent.

Abolition of PRT

Government respondents saw PRT as the main source of revenue in the early years of its imposition. However, by the early 1990s PRT was not generating sufficient revenues and that is why it was abandoned. 'PRT was expensive to the government. There was a lot of exploration but the fields discovered did not yield sufficient revenue for the government, given the different reliefs', said one government respondent. Another argued that after abolishing PRT on new fields in 1993, more revenues were generated, mainly as a result of abolishing offsetting exploration costs.

About a fifth of industry respondents said that the abolition of PRT was beneficial for the industry. The respondents further referred to the inefficiency and complexity of PRT. 'The structure of PRT could lead to counter investment decisions or gold-plating', said one.

However, approaching two-thirds of respondents argued that although abolition of PRT was beneficial it also led to the loss of the different 'generous' reliefs, particularly the oil allowance that protected marginal fields from paying the tax. One consultant related the detrimental effect of abolishing PRT to the resulting instability.

The supplementary charge and the 2002 changes

Ten respondents addressed the 1998 proposals, comparing an application of a Supplementary Tax (ST) with a re-introduction of PRT. The industry does not normally favour any increase in tax, however, when faced with either an increase in the CT rate or an application of PRT, nearly all respondents preferred the former option. 'The government could equalise the tax effect on fields by abolishing all upstream taxes and replacing this with a supplementary rate of CT, which delivers the same overall yield. This would remove the unnecessary complexity of the current system and remove disincentives to invest in mature fields,' suggested one. 'It is essential that any tax regime is focused on profit and not revenue. The CT Writing Down Allowance (WDA) ensures this condition is met. The relative fast depreciation provided by the WDA ensures that the after tax return is not significantly less than the before tax return, and consequently the CT regime does not inhibit activity.'

The other respondents were interviewed after the 2002 changes. One consultant argued that the abolition of Royalty and the WDA are the main benefits of the changes. As for the destabilising effects, the government respondent argued that dropping the proposed changes after a decline in oil prices (in 1998) did not mean that they would never be reconsidered. The industry respondent agreed: 'The latest changes, although unacceptable to the industry, primarily because of their destabilising affect, were in fact not totally unexpected.'

Alternative regime

All respondents from the industry argued that the government needs to maintain a stable regime. Furthermore, some 90% of respondents were against application of any special tax, whether PRT or Royalty. 'The least worst option is to change CT rather than applying PRT. CT is a corporate tax, thus it takes into account the company's overall portfolio, not simply a single project', said one. 'The most appropriate fiscal system is namely CT only. This ensures that the upstream industry is treated in the same way as any other industry in the UK. Since the returns in the oil sector in recent years have been below those that can be earned elsewhere in the economy, the intellectual case for additional taxation on oil and gas activities is not sustainable.'

A consultant said that PRT should not be applied because 'it is a complicated tax as it stands, and it is likely to create greater uncertainty, thus affecting investment decisions. Changing CT is simpler, more direct and unlikely to cause significant distortions and create greater uncertainty'. Two consultants noted that: 'PRT is a super profit tax, so to charge a super profit tax, companies should be making super profits in each field. This is not the case any more.'

Two respondents, however, preferred the PRT but said that re-introducing PRT 'after nearly ten years would be very difficult'. Additional alternatives suggested were: 'Link CT changes to the behaviour of oil prices', 'the recent changes need to be supplemented by additional incentives to explore (say, a 25% supplement on exploration costs)','apply a Resource Rent Tax (RRT) similar to Australia'.

Risk-sharing

On this issue there was a wide variety of opinions. When evaluating a project, investors base their evaluation on an average life of over 20 years. Stability of the fiscal regime was seen as crucial for creating a healthy investment environment and maintaining competitiveness. Two respondents commented on the partnership between the government and the industry as reducing investors' risk. 'The fiscal risk will never go away but, with meaningful discussions between the industry and government at such forums as PILOT,[1] we believe that the government is committed to ensuring that the UKCS remains competitive.'

On the other hand, three respondents from oil companies argued that oil companies developed their own strategies to find ways to adapt and learn to live with risk.

International competitiveness

All respondents agreed that there were several factors, such as costs, geology and exploration risk that precede looking at the international competitiveness of a fiscal regime. 'The fiscal regime cannot be seen in isolation from the prospectivity. Whilst in headline terms the fiscal regime for new developments in the UKCS is more attractive than, for instance, in Norway, the field sizes are smaller and unit costs higher in the UKCS than for typical new fields in Norway. At the exploration level Norway offers the potential for large discoveries while the UKCS does not.' The dominant opinion was that the current fiscal regime is 'fit-for-purpose' and 'well-attuned to the economic realities of the UK North Sea', where newly discovered fields cannot stand a 'harsher' system. 'The regime is also geared to maximize UKCS resources.'

The future

All respondents agreed that the future level of activity in the UK North Sea points to decline. As a consultant said: 'Most companies are pessimistic'. Two respondents argued that the UK North Sea is unattractive, particularly for large companies. 'On an international level, the competition over capital will be more significant over the next few months, there are many opportunities elsewhere for the big companies, and the UK is not on the list.' One respondent further added that the Government should now worry about the 'security of supply rather than... revenues'.

Nevertheless, 40% of respondents argue that it is the exploration activity which is in decline, not necessarily development and production. 'A lot of discoveries are waiting to be developed', stated one. Five respondents believed that the oil price was a significant factor in determining both the levels of activity and profitability in the UK oil province. 'The level of activity has probably only been sustained by the recent and continued high oil price.'

Adjustments

Although all respondents rejected the argument that the UK petroleum fiscal regime is weak, none suggested a further decrease in the tax rates. An industry respondent even argued that 'a regime based upon a CT rate greater than 30% might be appropriate in the event of the abolition of Royalties'. The implication is that no reduction in the tax rates is advisable.

Only one respondent in this survey suggested applying a tax that attempts to capture economic rent. Although three respondents argued that PRT was intended to for this purpose, the tax is described as having several deficiencies. The explanation can be partly an inability to clearly define economic rent.

However, other possible adjustments suggested can be considered. First, the abolition of PRT met criticism on one specific point, the abolition of the exploration reliefs, which are described as essential by the industry. This raises the possibility of introducing some exploration reliefs related to the current system. A consultant, for instance, said that: 'The recent changes need to be supplemented by additional incentives to explore (say, a 25% supplement on exploration costs).'

In fact, the general perspective of the industry is that exploration activity has been, and will continue to be, in decline and hence it is the development of existing fields which will determine the future of the UK oil province.

Another possibility would be to subsidise certain fields, like Don, where 'there is lot of oil still to come but given a technology barrier, it has been abandoned'. However, subsidising activity makes the tax more like a Brown Tax[2] hence imposes high risk on the government. Further, subsidies can lead to inefficient use of capital, a point acknowledged by an industry respondent who argued that 'the pre-1993 fiscal regime subsidised exploration activity, which led to an inefficient allocation of capital'.

A third possible adjustment is to allow the deduction of financial costs against the 10% Supplementary Charge, similarly to CT. As one consultant said: 'Such an alternative can be simple to implement.'

However, a fourth possibility suggests a complete change in the fiscal regime. Instead of PRT, the UK government can impose a Resource Rent Tax.

Conclusion

The main findings of the survey are summarised as follows. Taxation in the UK is seen as a major determinant of activity levels and trends. Tax instruments like Royalty and PRT are considered as non-neutral, a point confirmed when their abolition in 1983 and 1993 respectively, affected the activity in the UK North Sea. Royalty is seen as a regressive tax and the least desirable, hence its abolition is considered as essential. Nevertheless, the abolition of PRT elicited different opinions. The several PRT reliefs are considered as expensive to the government and can lead an inefficient allocation of

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LNG boom continues apace

Chris Skrebowski *looks at how LNG has become ever more competitive as production costs have fallen, while end-market prices have risen. As a result, the flexibility it provides to both buyers and sellers means it can provide effective competition in markets that are pipeline supplied and where only a few years ago LNG supply would have been uncompetitive.*

In *Petroleum Review*'s latest tabulation of global LNG projects – **Table 1** – records 65 LNG plants and nine gas-to-liquids (GTL) facilities to be built in the next seven to nine years. Over the last year, a number of projects have been firmed up, but relatively few new projects have emerged. Notable amongst these are the planned de-bottlenecking of the first three Atlantic LNG units in Trinidad; the new Olokola and West Niger Delta plants in Nigeria; the go-ahead for the fifth train of the North West Shelf joint venture at Karratha in Australia; and the Gorgon II plant to exploit the Jansz/Io discoveries in north-west Australia. There is also the possibility of a Snohvit II unit in Norway and a second train at Damietta (Damietta II) in Egypt.

In addition to the new proposals, a number of projects have moved from being probable to work starting on them – examples being Peru LNG and Bioko in Equatorial Guinea. [Note: In **Table 1**, if a project is described as a 'proposal' it is at the study stage, otherwise work is proceeding.]

Qatar appears set to become one of the largest, if not the largest, LNG producers in the world, with steady expansion plans for Ras Laffan by Qatargas and Rasgas.

In contrast to the very large-scale investment in LNG, the commitment to GTL is, so far, rather more tentative. Operators are still wrestling with the difficult economics and the commercial challenges of producing blendstocks at locations remote from where they are likely to be needed.

Commercialisation costs

The sheer number of LNG projects means that if they all go ahead, most, if not all, of the much discussed 'stranded' gas will be in the process of being commercialised. However, because LNG projects typically line up at least 20 years of gas supply before going ahead, this has the effect of sterilising gas reserves that then become inaccessible to other users. This contrasts with the ready fungibility of oil reserves.

For crude producers oil stabilisation, loading and freight costs represent around 10% of the delivered cost of crude oil. This is in sharp contrast to LNG, where the cost of liquefaction and transport can be over 40% of the delivered cost. This increases the incentive for owners of remote gas fields to both produce and deliver the gas to market. For truly remote gas the only realistic route is as LNG, while for intermediate distances pipeline supply becomes an alternative. However, pipelines suffer the disadvantage that there tends to be a 'lock-in' to certain buyers while,

Project	Details	Country	Operator	LNG cap (mn t/y)	Source fields	Resvs (tn cf)	Buyers/term contracts
Start-up 2004							
NWS JV	4th train	Australia	Woodside	4.20	N Rankin + 6 fields* 2nd p'line		Japan, S Korea, China
Rasgas II	3rd train	Qatar	ExxonMobil	4.70	North field	900*	India
Start-up 2005							
Atlantic LNG	4th train	Trinidad	Atlantic LNG	5.20	Cannonball, Trinidad offshore		US, Spain
Damietta LNG	1st train	Egypt	Segas	5.20	Nile Delta fields		Spain
Idku – ELNG	1st train	Egypt	Egyptian LNG	3.60	Simian Sienna (WDDM) fields	13	Gaz de France 20yr contract
Idku – ELNG	2nd train	Egypt	Egyptian LNG	3.60	Sapphire (WDDM) field(s)	13	BG Mkting to US, Europe
NLNG	4th & 5th trains	Nigeria	Nigeria LNG	8.20	onshore fields		BG Mkting to Europe, US
Qatargas	de-bottleneck	Qatar	Qatargas	1.50	North field	900*	UK and NW Europe
Rasgas II	4th train	Qatar	ExxonMobil	4.70	North field	900*	India
Start-up 2006							
Darwin	1st train	Australia	ConocoPhillips	3.00	Bayu-Undan	3.40**	Japan
Qalhat LNG	1st train (3rd/Oman)	Oman	Qalhat LNG	3.50	onshore fields		Europe, India
Oman LNG	de-bottleneck 1&2	Oman	Oman LNG	0.54	onshore fields		Korea, various companies
Oryx GTL Ph 1	GTL plant	Qatar	Sasol/Chevron	34 kb/d	North field	900*	
Snøhvit	1st train	Norway	Statoil	4.20	Snøhvit, Albatross, Askelaad	10.60	US, Europe

Table 1: Current global gas megaprojects

Project	Details	Country	Operator	LNG cap (mn t/y)	Source fields	Resvs (tn cf)	Buyers/term contracts
Start-up 2007							
Atlantic LNG	de-bottleneck T1-3	Trinidad	Atlantic LNG	–	Cannonball, Trinidad offshore		US, Spain
Bioko	1st train	Equat Guinea	Marathon	3.40	Alba field		BG Gas Mkting, to US 17yrs
Bontang	Train 1 expsn	Indonesia	Pertamina	3.50	onshore fields		Japan and Far East
Damietta LNG	2nd train	Egypt	BP	3.60	offshore fields		Eni, BP, EGAS
Idku – ELNG	3rd train	Egypt	Egyptian LNG	3.60	WDDM fields	13	
NLNG	6th train	Nigeria	Nigeria LNG	4.10	onshore fields		US, Europe
Qatargas II	1st/4th train	Qatar	ExxonMobil	7.80	North field	900*	UK
Rasgas II	5th train	Qatar	ExxonMobil	4.70	North field	900*	India
Skikda rebuild	rebuilding	Algeria	Sonatrach	3.80	onshore fields		
Start-up 2008							
Brazilian LNG	1 train proposal	Brazil	Petrobras/WM	2.50	BS-400, Santos Basin	15	
Camisea LNG	1 train	Peru	Hunt Oil	4.50	Camisea/Pagoreni/Mapaya fields		Mexico, US (Repsol to mkt)
Gorgon LNG	1st & 2nd train	Australia	Chevron	10	Greater Gorgon (10 f'ds)	40	USWC, China
NWS JV	5th train	Australia	Woodside	4.20	North Rankin + 6 fields*		Far East, USWC
Qatargas II	2nd/5th train	Qatar	ExxonMobil	7.80	North field	900*	UK
Qatargas III	5th train	Qatar	ConocoPhillips	7.80	North field	900*	US
Rasgas III	3rd train	Qatar	ExxonMobil	7.80	North field	900*	US
Sakhalin II	2 trains	Russia	Shell	9.60	Piltun and Astokh	17.30	Japanese buyers
Tangguh	1st & 2nd trains	Irian Jaya	BP, Pertamina	7.60	Wiriagar, Muturi, Berau	14.40	China, Mexico, S Korea
Yemen LNG	2 train	Yemen (Balhaf)	Total	6.80	onshore fields (Marib region)		India, Korea, US
Western LNG	1 train proposal	W Niger Delta	ConocoPhillips etc	5	West Niger Delta fields		
Start-up 2009							
Angola LNG	1st train	Soyo Angola	Chevron	5	offshore fields		US, Europe
Arzew	1st train Ain El Bia	Algeria	Sonatrach	3.80	Gassi Touil, Rhourde Nouse, Hamra	9	US, Europe
Brass LNG	2 trains	Nigeria	Chevron etc	10	onshore oil and gas fields		US
Greater Sunrise LNG	1st train	Australia	Woodside	5.30	Sunrise, Troubador, Loxton Shls	7.70***	China, Korea, Taiwan
Iran LNG	2-train proposal	Iran	NIOC/BP	9	South Pars	600*	China MoU from 2008
Mariscal Sucre	1-train proposal	Venezuela	Shell	4.70	Paria Penins. fields, Platforma Deltano	10	US, Mexico
NIOC LNG	2-train proposal	Iran	NIOC/BG et al	9.60	South Pars	600*	
Oryx GTL Ph 2	3-train facility	Qatar	Sasol Chevron	to 100 kb/d	North field	900*	
Persian LNG	2-train proposal	Iran	NIOC/Shell/Repsol	9	South Pars	600*	
Qatargas II	2nd train	Qatar	ExxonMobil	7.80	North field	900*	US, Europe
Qatargas III	6th train	Qatar	ConocoPhillips	7.50	North field	900*	
Pearl GTL (Ph 1)	GTL plant	Qatar	Shell	70 kb/d	North field prod of 800mn cf/d	900*	
Start-up 2010							
Brunei – Lumut II	3rd train proposal	Brunei	Shell	4.00	to be determined		Japan, South Korea
Gorgon LNG II	2-train proposal	Australia	ExxonMobil	10.00	Jansz/Io, Greater Gorgon fields	20	
Olokola	4-train proposal	Nigeria	Chevron	20.00	onshore fields		
Pluto LNG	2 trains	Australia	Woodside	5–7mn t/y	Pluto		
Rasgas III	4th train	Qatar	ExxonMobil	7.80	North field	900*	US
Start-up 2011							
Pearl GTL (Ph 2)	GTL plant	Qatar	Shell	70 kb/d	North field prod. of 800mn cf/d	900*	
Ras Laffan GTL	GTL plant	Qatar	ExxonMobil	154 kb/d	North field		
Possible projects							
Atlantic LNG	5th & 6th train prop		Trinid'd Atlantic LNG	10.40	offshore fields		US, Spain
Bandar Tombak	2-train proposal	Iran	NIOC/BG	9	South Pars	600*	
Bonny LNG	1-train proposal	Nigeria	NNPC/ExxonMobil	4.80	onshore fields		
Colombia GTL	GTL plant proposal	Colombia	BP				
Iran GTL	GTL plant proposal	Iran	PetroSA		South Pars	600*	
Libya LNG	Revamp+new cap	Libya	Shell	0.7 to 3.2	onshore fields		
MLNG IV	4th train	Malaysia	MLNG IV	6.80	offshore fields		Japan, Korea, Taiwan
Murmansk LNG	2-train proposal	Russia	Gazprom/partner	12	Shtokman field in Barents Sea	55.00	
Nigeria floating LNG	1-train proposal	Nigeria	Shell/Statoil	5	Nnwa/Doro offshore fields		US, Europe
NLNG	7th train proposal	Nigeria	Nigeria LNG	4.10	onshore fields		US, Europe
Oryx GTL Ph 2	GTL plant	Qatar	Sasol/Chevron	200 kb/d	North field	900*	
Pacific LNG	2-train proposal	Bolivia	Repsol/YPF	6	Margarita field	13.00	Mexico, California
Pars GTL	GTL plant	Iran	Sasol		South Pars	600*	
Pars LNG	2-train proposal	Iran	NIOC/Total	8	South Pars block 11	600*	India,
Qatargas IV	7th train proposal	Qatar	Shell	7.80	North field	900*	
Qatar GTL	6-train proposal	Qatar	Sasol Chevron	130 kb/d	North field	900*	
Qatar GTL 2	GTL plant	Qatar	Marathon	120 kb/d	North field	900*	
Ras Laffan GTL	GTL plant	Qatar	ConocoPhillips		North field	900*	
Rasgas III	Trains 6/7 proposal	Qatar	Rasgas	15.60	North field	900*	US, Europe
Snøhvit II	2nd train	Norway	Statoil		Snøhvit, Albatross, Askelaad	10.60	US, Europe
Sulawesi LNG	2-train proposal	Cent Sulawesi	Pertamina	6	Donggi field	4	

Source: *Petroleum Review* databases. * Total in field, **plus 400mn barrels condensate, ***plus 300mn barrels condensate

Table 1: Current global gas megaprojects

depending on the borders crossed, there may be strategic and political risks in committing to pipeline supply.

Supplying Ormen Lange gas via the Langeled pipeline to the UK really only involves agreeing the contract prices and getting the economics right. This is the easy end of the pipeline-supply spectrum. At the other end might be promoting a pipeline from Iran to India via Pakistan – a possibility that, so far, has always been blocked by the politics. At the moment, LNG supply from Iran to India looks more probable than pipeline supply.

In between there are a number of pipeline proposals that compete directly with LNG supply, such as the recently completed Greenstream pipeline from Libya to Italy. Whether expanding Libya's LNG plant to make it more competitive proves attractive will depend on both the relative attractiveness of pipeline supply and the proving up of additional gas reserves. Egypt, which is rapidly becoming a major gas producer will have two, maybe three, LNG trains in operation by the end of this year. These will directly compete with planned regional pipelines and a proposed cross-Mediterranean link.

International plans

Russia plans to exploit the Shtokman gas field in the Barents Sea, but, for the moment, appears undecided as to whether to export the gas via the proposed North European pipeline under the Baltic to Germany or whether to promote LNG supplies targeted at the US. The size of the Shtokman reserves (55tn cf) means both could be used. Concern about the inflexibility of pipelines and the likely commitment to a single customer is behind Russia's decision to route the Far East pipeline all the way to the Pacific, with a possible spur to China. Meanwhile, ExxonMobil's Sakhalin I project has committed to pipeline gas sales, while Shell Sakhalin II has opted for the LNG export route.

In North America, the much delayed Mackenzie Delta pipeline will probably be in operation by 2011/2012, but the Alaskan pipeline is unlikely to be in operation before 2015. As a result, there has been the tentative promotion of an Alaskan LNG project as an alternative egress route for the gas.

In the Middle East, both Qatar and Iran are rapidly commercialising their massive North field/South Pars reserves – although Iran has other options, including pipeline sales internally or externally, or re-injection into oil fields to boost recovery.

Various pipeline schemes from the Middle East are proposed – one of the most ambitious being Nambucco, which would link all the way from Austria to the Iranian border. The attractions of such a route is that potentially it could link gas supplies from Iran and the Middle East, Azerbaijan, Turkmenistan and Kazakhstan with the comprehensive gas grid of Western Europe. The dream is seductive – whether it proves to be realistic and operable remains to be seen.

LNG imports

What is not really in doubt is that the two great gas consuming areas – the US and Europe – are facing challenges from static or declining local supplies and, as a result, will become increasingly dependent on imports. High gas prices in both North America and Europe mean it is becoming increasingly attractive to source supplies via long distance pipelines or as LNG. In the case of the rapidly growing economies of China, south-east Asia and India, gas is rapidly becoming a key fuel, with its clean-burning properties making it highly attractive to regions attempting to mitigate air pollution.

As a result, in addition to very active exploration for gas throughout the region there is tremendous interest in LNG imports. Both China and India have had considerable exploration success in finding gas, but demand growth is so rapid that the two countries have both operating and planned LNG import facilities. The traditional LNG importers in the Far East – Japan, South Korea and Taiwan – continue to increase their LNG usage and have been notable buyers of future supplies from Australia, Russia and the Middle East. Exploration success and gas developments offshore Burma and Thailand appear to be easily absorbed by rapidly growing regional markets, notably in Thailand.

Ever more competitive

The conclusion appears to be that LNG has become ever more competitive as production costs have fallen, while end-market prices have risen. As a result, the flexibility it provides to both buyers and sellers means it can provide effective competition in markets that are pipeline supplied and where only a few years ago LNG supply would have been uncompetitive.

Just how attractive LNG has become can be gauged from the Pluto LNG project. Woodside Petroleum only discovered the Pluto gas field on the North West Shelf of Australia in April 2005, but by August 2005 it was announcing a Pluto LNG project start-up in 2010.

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expenditures. But the abolition of PRT seems to favour the large fields, as small fields are protected from the payment of the tax by various reliefs.

PRT was viewed as inferior to CT; and there was a general suggestion that the oil industry should not be treated differently from other industries. But the abolition of PRT led to the removal of the exploration and appraisal reliefs, as well as a reduction in the perceived level of risk sharing with government, an important attribute of the previous regime.

The 'least worst option' is to combine an increase in the Corporation Tax with the abolition of all other upstream taxes. Yet, the stability of the regime is viewed as of particular significance in maintaining investors' confidence. Maintaining and improving government partnership with industry is also considered equally important. The proposition that the UK regime was weak was rejected by all respondents. Instead, the regime was seen as 'well attuned' to the economic realities of a mature oil province. All respondents argued that the level of activity in the UK North Sea, particularly exploration, is declining, but both oil price and taxation can play an important role in determining both activity levels and profitability of the industry.

The survey attempted to identify acceptable alternatives. Five main propositions emerged – the imposition of an income tax with the abolition of all special petroleum taxes, as suggested by majority of respondents; the application of a RRT; the introduction of exploration reliefs as well as subsidies; and, finally, the deduction of financial costs from ST. Introducing exploration reliefs depends on government and industry's future outlook for North Sea activity, which seems to be pessimistic. The main concern is to encourage the development of discovered fields and extend the life of existing fields. With regards to subsidies, such an alternative seems very difficult to apply as it transfers too much of the risk on to the government.

1. PILOT is a joint government/industry initiative, with the goal of maximising activity and efficiency for UK oil and gas operations.
2. A Brown Tax is levied as a fixed proportion of a project's net cash flow in each period. When the net cash flow is positive, firms have to pay the tax; when the cash flow is negative, firms receive an injection of cash from the government.

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Unravelling the future of the UK energy market

Utilities may hope that as the residential energy retail market matures the regulator's touch will lighten and theirs can become more like most other retail industries. Instead, this hope will become a rueful wish when the regulator deepens the role of energy retailers in combating fuel poverty, suggests Daniel Legg, *Datamonitor Utilities Analyst.*

The following two visions of the future are adaptations of two scenarios from Datatmonitor's report The future of energy retail in the UK: scenario forecasting for the residential sector.

Fuel poverty is increasing simply because energy prices are rising faster than incomes, particularly those in the form of benefits or state pensions, which tend to be linked to inflation rather than average earnings. This matters particularly because the current government has identified itself so closely with the fight against deprivation, and this identification is strongest with the man (Gordon Brown) who hopes to become the next Prime Minister.

Utilities do not like hostile commodity markets at the best of times; the added combination of rising fuel poverty and the onus of corporate social responsibility can only make suppliers increasingly cautious. A major part of the response is to build up their structural hedges, which is a culmination of a process begun years ago rather than anything new.

The consequence of the big six utilities having a broadly similar balance between residential customers and upstream assets is vanishing scope for competitive pricing – historically the driver of customer switching. Asset-light suppliers have in the past been able to take customers from asset-heavy competitors when wholesale prices were falling but were then squeezed hard when the wholesale price turned and owning assets became an advantage again. This will no longer happen when everyone is operating on the same asset strategy. Utilities will be able to use their control all the way along the value chain to stabilise end-user prices, taking the sting out of wholesale volatility and improving their profitability.

If utilities resent the increased regulation, other wishes come true. The overriding importance of price in the switching market has been the bane of suppliers that want high margins without a shrinking customer base, and at last they get what they want – non-price competition. As price differences between suppliers become trivial, the two-tier pricing model breaks down. Instead, competition is increasingly brand driven and focused on particular demographic segments, with a related increase in the importance of green energy and affinity partners.

This is not all good news for the major utilities. Attracted by growing profit margins and the role of brand in energy supply, more supermarkets may follow Sainsbury's lead and enter the energy retail market. (Entry into the market is defined by ownership of the customer experience rather than simply acting as an affinity partner.) Although the 'customer champion' identities of the supermarkets fit well with the government's emphasis on the social role of the energy retail industry, the fact that they are not structurally hedged in the way the major utilities are means that they never present a serious challenge.

Possible alternative

If a future of regulatory intervention and apparently oligopolistic competition sounds like an unfavourable outcome it may be salutary to consider a future in which a weaker national regulator cannot stop competition from taking a far more dramatic course. We begin at the same place – high wholesale prices – but it is not the effect on the socially disadvantaged that is the concern. Rather, it is the effect on margins that sparks the events that follow.

Dissatisfied with low profitability, the major UK energy suppliers decide to improve profitability by aggressively increasing their scale. Coincidentally, but significantly, failure to ratify the EU constitution leads to a refocus on the implementation of existing directives. This, in turn, creates a policy environment that supports energy market consolidation.

The purpose of 'aggressively increasing scale' is to drive a competitor from the market – or at least severely weaken it with the hope of improving margins thereafter. Ofgem would naturally be hostile to this kind of move, which is why it is important that European energy policy predominates over Ofgem's national position – European policy makers have tended to be more tolerant of national champions.

Although this is a battle for scale, it is not fought simply by squeezing margins as in previous battles; wholesale prices remain too high and margins too low for this to be possible. Instead, the resulting sales war is primarily cost-led, with utilities having to focus on improving the efficiency of their sales and service functions in order to compete. However, squeezing the last pounds from the sales and service functions is not enough, so product development increasingly moves in the direction of multi-utility bundles.

Utilities believe that expanding their product ranges is the best way to cut costs and attract customers, as well as being the best opportunity for future profit growth. Chastened by their previous forays into non-energy products and services, few will be quick to venture beyond home insurance products such as central heating or drains care. On the other hand, it would certainly be possible to buy a small telecoms business if the thought of more integration of customer bases is not too daunting.

This strategy works. For example, unable to compete, one of the two

Scottish-based energy suppliers exits the residential market. This would present an opportunity for a major European utility to enter the UK market – Vattenfall or Enel for instance – but the low margins may be unappealing. The price may also be too high, bid up by the UK incumbents because they have more to gain by taking a rival out of the market. An alternative to a straightforward takeover would be an asset swap, with one supplier becoming a dedicated operator of a larger networks business. It would not necessarily be the loser of a sales war that opted to do this – a supplier with expertise in network operation may calculate that it could get a very good price for its supply business from a competitor desperate for an end to the sales war, and at the same time profit from the synergies of taking on another network business.

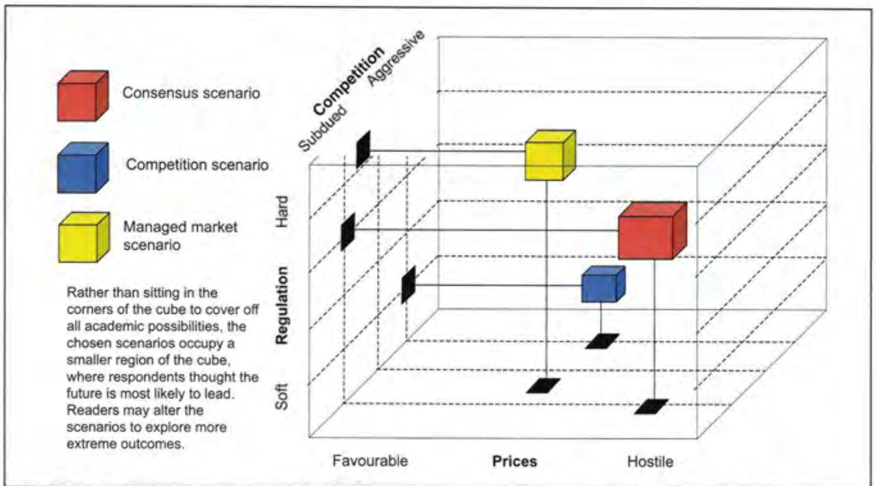

Figure 1: The three scenarios identified cover a selected portion of all possible outcomes

Possible scenarios

These alternatives are adaptations of two of the three scenarios in Datamonitor's *Future of Energy Retail in the UK*. The scenarios were built up from 40 possible events that were rated for likelihood and impact by a cross-section of utility executives and industry analysts. A base case scenario was formed out of events that respondents thought most likely and is presented in the report as the consensus scenario. It is the basis of the first scenario in this article. Events that respondents thought less likely formed a 'watch' scenario, presented in the report as the competition scenario, which forms the second part of this article. The report also contains a third scenario, which was constructed from the events over which utility executives and industry analysts disagreed most. Ominously called the 'analysts' warning', it describes a future in which the government resorts to more active management of the industry in order to push through a nuclear agenda.

Figure 1 indicates the range of possible outcomes covered by the three scenarios. Because the scenarios were based on a survey that was intended to adumbrate likely futures, none of them cover the extremes of regulation, competition or pricing. In effect, respondents did not think them likely enough to warrant further consideration.

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The Energy Institute (EI) and the Consilience Energy Advisory Group (CEAG) are pleased to invite you to attend a free seminar and drinks reception on Tuesday 27 September from 16.00 at 61 New Cavendish Street, London W1G 7AR, UK.

Speakers:
Dr Kerr and Liz Bossley are joint authors of *Climate Change and Emissions Trading: What Every Business Needs to Know* and will present a summary of their findings.

***Climate Change and Emissions Trading: What Every Business Needs to Know* will be available to purchase at the seminar for a discounted price of £75.00 (normal price £99.50)**

To book one of the limited number of places at the seminar please respond to: Arabella Dick, Energy Institute of 61 New Cavendish Street London W1G 7AR, t: +44 (0) 20 7467 7106 f: +44 (0) 20 7580 2230 e: arabella@energyinst.org.uk www.energyinst.org.uk

energy INSTITUTE

EI Autumn Lunch 2005

Guest of Honour and Speaker:

***Joan MacNaughton*, Director-General, Energy Department, DTI**

Monday 17 October 2005, The Berkeley, Wilton Place, Knightsbridge, London, SW1X 7RL

The EI Autumn Lunch is a prestigious and established date in the energy events calendar, providing a unique opportunity to hear a respected figure speak on contemporary global issues affecting our industry.

Joan MacNaughton, Director General, Energy, Department of Trade & Industry (DTI), joined the Home Office in 1972 with a degree in Physics from Warwick University. She has had a wide range of policy and managerial jobs in her Civil Service career – managing large-scale organisational change in several different sectors. She has been Principal Private Secretary to three Cabinet Ministers, and has also spent time in the private sector. Since January 2002 she has been DG, Energy, DTI, responsible for Oil & Gas, Nuclear Industries, Coal Policy, and the Engineering Inspectorate. In early 2003, she oversaw the publication of the Government's Energy White Paper, which defines a long-term strategic vision for energy policy combining the UK's environmental, security of supply, competitiveness and social goals. Overall aims of the Group include working with others to promote competitive energy markets, while achieving safe, secure and sustainable energy supplies.

In Spring 2004 she was elected as Chair of the International Energy Agency Governing Board. The IEA, based in Paris, is an autonomous agency linked with the Organisation for Economic Co-operation and Development (OECD). It was formed in the wake of the 1973/74 oil crises with energy security as its core activity and includes key consuming countries such as the US and Japan.

To apply for tickets, please complete this form in BLOCK CAPITALS and return it to the address below, together with payment in full.

Jacqueline Warner, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK.

t: + 44 (0) 20 7467 7116, f: + 44 (0) 20 7580 2230, e: jwarner@energyinst.org.uk

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(for bookings received before 2 September 2005)

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Early bird rate:
£125.00 (£146.88 inc VAT)
(for bookings before 2 September)

Standard rate:
£140.00 (£164.50 inc VAT)

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

Ticket price includes pre-luncheon drinks, and a 3-course lunch with wine. Cigars and liqueurs are not included. In the event of cancellation of attendance by ticket purchaser a refund, less 20% administration charge of the total monies due, will be made provided that notice of cancellation is received in writing on or before 26 September 2005. No refunds will be paid, or invoices cancelled after this date.

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

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

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No compromise on safety

BP's commitment to HSE performance is the driving force behind 'smart' bitumen storage for asphalt manufacturing, writes Phil Shirley.

Above: BP Bitumen is investing with customers to increase and improve storage facilities at strategic sites, utilising a combination of latest storage and transportation technologies for managing customer delivery and storage

Improvements in asphalt technology have played a key role in expanding the highway network, as well as in accelerating pavement maintenance and reconstruction operations with minimal delays to the travelling public. The goal in developing highways has been and will be to achieve comfort, safety, and efficiency for highway users in a cost-effective way.

The challenges that face the engineer and the asphalt industry are many-sided. Some of them are straightforward; others are complex, requiring new concepts and appropriate direction to achieve solutions. For the asphalt producer, though, the challenges include tightening HSE demands and increasing competition, which requires plants to get more and more cost efficient.

The application of sensors, automation, and information technology, for example, have significantly changed the way in which refineries operate and have been successfully used by the petroleum industry for many years to lower costs, increase profitability and improve customer service across the supply chain. The collective changes are sometimes characterised as constituting 'smart refining' and, because the transfer of such knowledge is relatively straightforward, the development of similar technology for bitumen storage applications has the potential to enable the asphalt manufacturing industry to develop its own 'smart' way of working.

Getting the right quantity of high quality material to customers at the right time is the main driving force behind the design of most asphalt plants. In recent years, the focus of new facilities has certainly shifted and now also encompasses a range of environmental issues, output performance and safety.

BP initiative

Thanks to an innovative and pro-active initiative by BP Bitumen, a growing number of the UK's 300-plus asphalt plants are undergoing 'modernisation', which will see them improve HSE performance for bitumen storage.

Specifically, a combination of enhanced storage and transportation capabilities, utilising the very latest in design and technology and coupled with the implementation of new safety standards, are behind recent developments at five key asphalt manufacturing plants in the UK, with another five scheduled to undergo similar improvements before the end of the year.

'This is about setting new standards and we have worked hard to establish a benchmark in HSE performance with the bitumen industry,' said BP Bitumen's Supply & Logistics Manager Peter Clement. 'We are delivering real benefits that go beyond financials, including environmental performance, safety, process efficiency and customer satisfaction.'

The Southern North Sea: the lynchpin of european supply and demand

6 October 2005

British Medical Association, BMA House, Tavistock Square, London WC15 9JP, UK

Jointly organised by:

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logical ADVANTAGE LTD

The UK is no longer self-sufficient in gas and increasingly will have to depend upon gas supplies from overseas, either via pipelines from Europe or LNG imports. Also, due to the rapid increase in oil price, and thus energy prices in general the price of gas has increased. Further, as with the UKCS in general, the global majors have been reducing and/or exiting the SNS and the major regional operators now include companies such as Tullow & Perenco.

The intention is for the LAL/EI SNS conference to be highly interactive and provide the opportunity to discuss the key issues currently affecting the SNS. The conference will present and examine how the changing gas market will effect future SNS operations e.g. what is the impact on SNS gas production and contracting strategy – now and in the future? Further the conference will review and facilitate discussions about the current other factors affecting the future development of the SNS and operations e.g. the impact of the new players, the interest of the utility companies gas qualities etc. Delegates will also have a chance to hear from some of the current participants in the SNS about their current plans and how they see the future.

This conference will appeal to asset, business development, commercial and legal managers in the oil companies (both operating and non-operating) and gas utility companies, commercial/ business development managers in the contracting and supplier communities as well as those included in the financial community who wish to have a greater understanding of the future of the SNS market.

Confirmed speakers:

- **Christophe Schlicter, Managing Director, RWE Dea UK**
- **Richard Harper, RWE Trading**
- **Mark Hughes, Gaz de France**
- **Ken McKeller, Managing Director, Petroleum Services, Deloitte**
- **Paul McDade, Tullow**

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Wider implications

The BP Bitumen initiative, however, is seen by many as a positive catalyst for the biggest modernisation programme in the history of the UK bitumen industry. By constructing larger storage facilities with modern instrumentation technology and reporting procedures designed to reduce spillages and improve overall safety within industry, not only is BP Bitumen increasing safety performance, it is also creating a new green climate of change within the bitumen industry.

'The work we are doing is delivering real environmental benefits,' Clement said. 'These include less harm to the environment through a reduction in spillages, larger loads that result in less traffic, less emissions, and less risk. Our new storage tanks are better insulated and more heat efficient so they use less energy.'

'We are bringing in changes that will inevitably shape the future of bitumen storage and transportation,' Clement commented. 'We are the first, and currently only, bitumen supplier in the UK to manage our customer inventories using an Internet-based telemetry system. This remote stock management system is used to manage risk.'

BP Bitumen has, in fact, been rolling out logistics solutions using large tanks within its customer base for several years now, but this latest development, driven by a desire to improve service to customers and increase plant safety, is now leading the way in promoting bitumen stock management.

Staying competitive

The asphalt industry produces more than 26mn t/y of asphalt. The production process involves blending the aggregates and then heating them to a temperature suitable for coating with the bitumen binder. Bitumen manufacturers operate in an extremely competitive environment and in order to ensure success they have to match unrivalled customer service with manufacturing excellence. It's a fine balance, but Clement says: 'The work we are doing to increase HSE performance and process efficiency will help our customers remain competitive in their own markets.'

As far as performance of the product is concerned, while strength comes from the aggregates, the binding agent is normally an oil-based bitumen derived from crude oil. BP Bitumen, one of the world's leading binder suppliers, is the European market leader in polymer modified binders (PMBs) for hot mix asphalts. These leading-edge binders include the Olexobit Universal and Specialist ranges of PMBs, using elastomeric synthetic rubber modified bitumens specially developed by BP to provide high performance and economy in a wide range of applications. These products have been extensively proven in several countries in thin surfacings, asphaltic concrete, stone mastic asphalt, porous asphalt and hot rolled asphalt applications. Essentially, these binders offer enhanced performance over the entire in-service temperature range, resulting in greater cracking resistance at low temperatures and reduced deformation at higher temperatures. Adhesion, cohesive strength and fatigue life are also significantly improved. The unique PMB system technology developed and employed by BP Bitumen has set the benchmark for product performance.

Safety practices

BP Bitumen products are delivered to a significant number of the 300-plus asphalt manufacturing plants throughout the UK, which involve approximately 1,300 bitumen storage tanks. Any spillages from these bitumen storage tanks as a result of overfilling have a potential for serious injury as bitumen is stored at elevated temperatures and has a large thermal capacity.

During the past few years, ongoing analysis of tank overfill incidents, carried out as a matter of course by the Refined Bitumen Association (RBA) – the body representing the UK bitumen industry, raised the issue concerning the provision of information on the management of bitumen storage tank measuring equipment at customers premises.

A comprehensive safety audit of asphalt manufacturing plants was carried out by BP Bitumen's Instrumentation Engineer Derek Maddock in the UK to address this industry wide problem and the findings were published in an *RBA Asphalt Industry Bitumen Storage Tank Measuring Systems Report*.

'There are inconsistencies across the industry,' said Maddock. 'These include the types of tank content measuring equipment used, the terminology used in defining tank contents, the methods used to determine available tank capacity and even the understanding of these concepts.' Consequently, a new safety guide, which is essentially an abbreviated version of the RBA report, has been launched and is in the process of being distributed. The booklet, *Guidance for Safe Bitumen Tank Management*, which explains the fundamental principles that need to be adopted at all plants to reduce the risk of tank overfill incidents, could help in the future management of bitumen storage by providing, for the first time, practical advice on achieving much needed consistent tank and inventory management standards within the UK bitumen industry.

BP Bitumen plans to remote stock manage approximately 40% of its bitumen volume delivered to customer sites by 2006

Dr Tony Harrison, Technical Director of the RBA, said the new guide is aimed at plant operators and will be delivered to every site in the UK. 'It's a significant development for the industry and is designed to consolidate existing safety procedures and further promote the importance of safety standards within the UK bitumen industry.'

BP Bitumen first used remote stock management and extra large storage tanks at Foster Yeoman's Purfleet manufacturing plant in Essex two years ago. Since then, it has modernised another five plants, with five more scheduled for completion over the next year. 'These are sites with larger throughput,' Clement said. 'Our target is to modernise 40% of our overall volume by 2006.'

The sites include Aggregate Industries asphalt plants in Leicestershire and Peterborough and Hanson asphalt plants at Builth Wells and Penderyn in Wales, as well as Foster Yeoman's plant at Purfleet. The modernisation work includes new 150-cm tanks, some of which utilise a 'mother-daughter' system, which is basically a transfer system that automatically fills existing smaller working tanks when their contents reach pre-described levels. The transfer system has a number of sophisticated controls that ensure safe actuation of the valves and pumps. Reliable level controls and back-up equipment prevent the danger of overfilling the working tanks.

'Telemetry has been used within other industries for years but it is relatively new to the asphalt industry for bitumen storage,' Clement said. 'We use the latest telemetry from Siemens – known as Levelwatch – which allows us to remotely monitor the contents of each tank via the Internet. This, in turn, allows us to plan delivery requirements more efficiently, rather than relying on "just-in-time" telephone orders, which place unwanted pressure on scheduling.'

The Internet-based system, which is linked either via a cellular or landline telecommunications device fitted at the site, is fully integrated so that the customer, BP Bitumen and its logistics supplier Exel are linked in a communication network. The levels of tanks, some of which are monitored by a non-contact radar device, enable Exel to maintain a 24/7 level watch.

BP Bitumen has also invested in a new fleet of road tankers, built to the highest specifications by French company Magyar, one of the leading European manufacturers of stainless steel tankers. 'We chose the Magyar design following a thorough search for the best fleet replacement solution,' Clement said.

Magyar's stainless steel tanker offers potential lower whole-of-life costs and the use of stainless steel ends corrosion problems associated with traditional mild steel barrels.

There is far more to the new Magyar design, however, than the use of stainless steel. The new tankers are equipped with latest technology discharge management systems and discharge line clearing, which maximise both safety and delivery performance. Other safety features include two pressure gauges, one situated at the air inlet at the front of the tank and one at the rear to allow the driver to see the pressure of the tank during discharge. Previous tankers had only one pressure gauge at the front of the tank. BP's new Magyar vehicles are also fitted with Knorr Bremse TRSP electronic braking systems to improve trailer stability and prevent rollover.

'Changes within the industry continue to increase pressure on the performance of both the plant and the delivery vehicles,' Clement said. 'Several factors persuaded us to modernise the storage tanks and the road tankers, and the remedy was to increase bitumen storage capacity and create more delivery flexibility. We have achieved both and are now firmly focused continuing to improve consistency.'

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Oil Depletion – Facing the challenges

Wednesday 2 November 2005
Energy Institute, 61 New Cavendish Street, London W1G 7AR

Tickets:
Member: £90.00 (£105.75 inc VAT)
Non-Member: £130.00 (£152.75 inc VAT)

There is mounting concern that global oil supplies may peak in the near future. How realistic is this and where will incremental supplies come from? What are the implications for the transportation sector especially for cars and other road transport?

In this important and timely conference industry experts will explain the current oil supply challenges and detail the potential of alternative supplies such as the Canadian Oil Sands. Recent developments in improving vehicle and fuel technologies will also be addressed in an exciting programme that offers both answers and a debating forum.

Confirmed speakers:

- **Martin Fry,** Director, Martin Fry and Associates
- **Chris Skrebowski,** Editor, ***Petroleum Review***
- **Roger Bentley,** Senior Research Fellow, Department of Cybernetics, The University of Reading
- **Claire Durkin,** Head of Energy Markets Unit, DTI
- **Jason Nunn,** Director, Upstream Services, PFC Energy
- **Robert Skinner,** Director, OIES
- **Malcolm Watson,** Technical Director, UKPIA
- **Nick Owen,** Senior Manager, Technology, Ricardo UK

For further information or to book a place at this event please contact: Arabella Dick, EI Events Organiser, Energy Institute, 61 New Cavendish Street, London W1G 7AR. t +44 (0)20 7467 7106 f: +44(0)20 7580 2230
e: arabella@energyinst.org.uk

www.energyinst.org.uk

EI Oil and Gas Training 2005

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NEW COURSE

Working capital management in the oil business

14–16 September 2005

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

*includes complimentary Affiliate membership to the Energy Institute

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

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

Who should attend?

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

Supply and distribution: organisation, operations and economics

20–23 September 2005

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

*includes complimentary Affiliate membership to the Energy Institute

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

Who should attend?

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

NEW COURSE

European and UK gas supply and demand

27 September 2005

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

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

Who should attend?

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

Oil and gas industry fundamentals

28–30 September, 28–30 November 2005

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

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

Who should attend?

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

NEW COURSE

Safety in refinery and petrochemical plant operation

4–7 October 2005

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

ifp enspm FORMATION INDUSTRIE IFP TRAINING

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

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

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

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EI Oil and Gas Training 2005

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Economics of the oil supply chain

10–14 October 2005

£2,150 (£2,526.25 inc VAT)

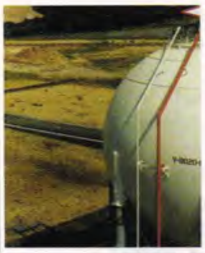
INVINCIBLE

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

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

Who should attend?

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



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

11 October 2005

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

*Includes complimentary Affiliate membership to the Energy Institute

Topics covered will include:

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

LNG – Liquefied natural gas industry

12–14 October 2005

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

*Includes complimentary Affiliate membership to the Energy Institute

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

Who should attend?

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

Trading oil on international markets

17–21 October 2005

£2,800 (£3,290 inc VAT)

INVINCIBLE

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

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

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

Planning and economics of refinery operations

18–21 October 2005

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

IFP enspm FORMATION INDUSTRIE IFP TRAINING

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

Who should attend?

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

Forthcoming 2005 training courses

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

For more information please contact Nick Wilkinson

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

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Asian Development Bank helps promote renewables

Industrial development and a rapid increase in the number of vehicles on the roads of many Asian countries have caused a large rise in airborne pollution in many areas throughout the region. As part of efforts to reduce environmental pollution and encourage sustainable energy consumption, many countries in the Asia-Pacific are planning to make greater use of renewable energy by developing important indigenous renewable resources. David Hayes *reports.*

Above: Washing vetiver roots before distilling essential oils in Java, Indonesia
All photos: David Hayes

One organisation helping to promote the use of renewable energy in Asia is the Manila-based Asian Development Bank (ADB). In 2003, the ADB approved project loans totalling $6.1bn, the highest since 1997, of which energy projects accounted for 12% of the loan total. Renewable energy projects currently form only a small part of the ADB's energy loan portfolio, but are becoming more common, particularly in rural development schemes.

Hydroelectric power and natural gas have been the two energy resources to have benefited from most ADB development support, while oil and petroleum development, coal and the nuclear power industry have been left to private companies and state-backed organisations to develop.

A growing range of energy sources are likely to be developed under the Bank's renewable energy and energy waste reduction initiatives, although energy resources chosen will depend on the particular countries and areas where schemes are implemented. Hydropower will remain an important renewable energy resource and most projects will be either small or mini-hydro schemes. Wind power, solar energy and biomass also are likely to become important renewable resources.

'ADB's Energy Policy 2000 says ADB will promote indigenous non-polluting energy. So it is something we want to do,' noted Samuel Tumiwa, Energy Specialist in the ADB's South Asia Energy Division. 'For the borrowing countries it is different. India is well off with renewables, while others are just getting into it, especially in South Asia. We have done photovoltaic schemes as part of rural development projects in Pakistan, Bhutan and Indonesia, not as energy sector projects. It's better that way as the economic returns are tied to health care and other issues like income generation in rural development, so the renewable schemes are more viable [than if they were stand alone power generation projects].'

Renewable energy schemes can be beneficial for reasons other than simply providing energy. Agricultural waste, which releases harmful methane into the atmosphere when decomposing, can be used to produce biogas for use in homes or small factories, or can fuel small power plants.

Renewable energy schemes are also increasingly being used to provide rural electrification in areas where it would not be economical to install a power transmission line to bring grid electricity supplies. Apart from providing electricity for use in rural homes, schools and medical centres, renewable energy schemes also supply electricity to power agricultural processing equipment and cold storage facilities, which help to increase rural incomes and living standards.

Indonesia, for example, is using a $161mn ADB renewable energy loan to construct small and mini-hydropower projects, as well as geothermal energy schemes, that are planned to benefit an estimated 5.2mn people – of whom 1.5mn live below the poverty line. Some 12 projects have been identified for construction on six islands – Lombok, West Kalimantan, Gorontalo, Flores, Papua and North Sulawesi. Two small hydroelectric schemes are due to be built in Papua and North Sulawesi, where a small geothermal plant will also be sited. The other schemes planned for Lombok, Flores, West Kalimantan and Gorontalo, with the exception of a mini-geothermal plant on Flores, are all mini-hydropower dams.

In addition to the loan, Indonesia is using ADB consultants to study the use of palm oil plantation waste for the production of biogas. Indonesia has about 300 palm oil mills that produce over 4mn tonnes of palm oil annually, making the country the world's second largest producer after Malaysia. Currently, palm oil mills lack knowledge and access to suitable technologies that can transform solid and liquid oil palm biomass waste into gas, electricity, biodiesel and fertiliser, while eliminating the polluting impact these waste materials now have.

One palm oil mill with the capacity to process 60 tonnes of oil palm fruit bunches per hour can produce 11,400 cm/d of methane from wastewater and generate over 1,500 kW of electricity. The consultants will prepare a report analysing local and international waste management practices in the palm oil industry. The report will identify groups of palm oil mills that could jointly exploit their renewable energy production potential, and include feasibility studies of financial and economic support required for the proposed renewable energy projects to be viable.

Closer to the ADB's Manila head office, the Bank is providing a $1.5mn grant from its Japanese Fund for Poverty Reduction to install renewable energy systems in eight villages in Negros Occidental in the central Visayas region of the Philippines that currently depend on kerosene, batteries and candles for energy.

Malaysia – Loading oil palm fruit on to trucks

A renewable energy system will be set up in each village, using micro-hydropower, solar, biomass or wind power. An association will be formed in each village to operate the renewable power system and collect payments, while the ADB will provide credit for a revolving fund to purchase lighting, tools and other equipment to connect households and small businesses such as community-owned rice mills and mini ice plants for food cold storage.

Small Pacific Island states also are looking to use renewable energy to improve living standards among remote communities. Research by ADB consultants shows that about 70% of Pacific islanders have no access to electricity. Remote communities are worst affected as these depend on expensive fossil fuels for power generation and transport. Energy costs in remote islands are three to four times higher than in Pacific island capital cities, and are higher even than in Australia and New Zealand.

To help remote villages in two Pacific island nations, the ADB has awarded the Cook Islands and the Federated States of Micronesia a Danish-funded $600,000 technical assistance grant to develop a policy, legal and institutional framework to establish a viable private sector-run energy market using renewable resources that include hydropower, wind, solar, biofuel, geothermal, ocean thermal and wave/tidal energy.

Central Asian support

Rural communities in remote areas of Uzbekistan could also benefit from ADB-funded project support as the result of a recent $350,000 ADB study to assess the Central Asian country's potential and options for renewable energy development. With most existing power plants old and unreliable, and overall current energy supply worsening, Uzbekistan is forecast to face a 10% shortfall in primary energy supplies by 2010, which will worsen unstable power supplies in major irrigation-dependent agricultural regions and increase the risk of crop failure.

The renewable energy potential of remote regions is high, particularly for small hydropower, of which only 30% of the potential is developed. Solar power could benefit remote villages and the many sheep farms, while wind, biomass and geothermal resources also could be developed – depending on what assistance the Uzbek government requests the ADB to provide following deliberations over the consultants' report and recommendations.

Tajikistan and Kyrgyzstan also face similar renewable energy options in remote areas, as do the Himalayan kingdoms of Nepal and Bhutan. Nepal, where the Bank has supported hydropower development in previous energy sector projects, is discussing the possibility of ADB-funded support for a rural electrification scheme. ADB's Samuel Tumiwa noted that both Nepal and Bhutan, which currently derives most of its electricity from run-of-the-river hydropower dams, want to install roof-top photovoltaic systems to expand household energy supplies.

Pakistani projects

Pakistan, meanwhile, is discussing a number of renewable energy schemes for which the ADB is expected to provide loan finance. 'For Pakistan, we have approved a project preparation technical assistance grant to assess renewable energy resources and to conduct a pre-feasibility study for six to 12 projects,' Tumiwa said. 'We have hired a lawyer to look at the electricity regulatory framework such as prices and other issues; also a specialist in wind power. But when you look around the world, most renewables projects are private and do not involve government investment. We will talk to the Pakistan government and suggest if the private sector can do it.'

Development of mini-hydro and micro-hydro power projects is already well advanced in north-west Pakistan and some other regions of the country. The government is also backing efforts to develop wind power. About 50 windmill towers have been built so far, while research has shown evidence of a wind tunnel in the southern Sind and Baluchistan provincial areas. 'Pakistan wants us to look at photovoltaic energy. The ADB also is thinking about mini-hydro schemes using waters from glacial melt for run-of-the-river schemes,' Tumiwa said. 'Punjab irrigation schemes are another possibility as there is a 12-ft water head for local hydropower use. They could use a drop in canal height for hydropower generation. Each drop could generate from 8 MW to 24 MW per drop. It is a low head, but there is a high volume of water flow.'

'We would like to help with micro-hydro schemes as well, but too many stages are involved and by the time the money has reached village level it is too expensive to borrow. It's usually at 9% to 11% interest, so it is not feasible. Because the way the ADB is structured we have to do bigger individual micro-hydro packages of 8 MW upwards and bundle projects up to 40 MW to 80 MW. Smaller projects only work if the government borrows.'

Renewables development

Apart from funding renewable energy projects and providing consultancy services to support renewables development, the ADB has other ways of supporting renewables development. The Bank has taken a $20mn stake in an energy efficiency fund run by the FE Clean Energy Group that is designed to help small and medium-sized firms in Asia. Two other private equity funds supporting renewable energy development have also requested the Bank to make equity investments in their funds, which lend capital to projects in various Asian countries.

Meanwhile, in India, which has developed a successful national renewable energy programme, the ADB has provided finance to the India Renewable Energy Development Authority (IREDA) to use as revolving credit to fund various renewable energy schemes. The Bank was due to provide IREDA with a second loan, this time for $200mn to use as revolving credit. So far, the loan has not been taken up, apparently because IREDA has access to cheaper loan finance from other sources. 'ADB money is not as competitive as it used to be,' Tumiwa commented. 'It's only competitive if the project includes large foreign equipment procurement or is a large generation project.'

The ADB is looking at other areas where it can support renewables development in India. One possibility involves providing partial loan credit guarantees to stimulate Indian banks to lend to energy efficiency projects. While no details have been finalised, the Bank might offer to assume 50% of the loan risk of borrowers defaulting to encourage banks to lend.

'We are also considering support for Pakistan and other countries where banks have liquidity but no experience of lending for energy efficiency pro-

Ploughing a rice field, Java, Indonesia

jects,' Tumiwa commented. 'To construct a biogas project the developer has to mortgage the whole plant not just the power plant section. So ADB would guarantee part of the banks' risk of their client defaulting.'

China, meanwhile, has been less successful in renewable energy development in spite of its large clean energy needs. Although able to finance energy development itself, the government has decided to maintain ADB involvement in energy-related issues to benefit from the Bank's wide ranging technical and management expertise. The government's main objective for energy sector development until 2020 is to reduce the growth of coal use and coal-related environmental pollution. According to the Tenth Five-Year Plan (2001–2005), China will increase the use of renewable energy resources to account for 5% of total electricity output by 2005.

While this target has already been met, maintaining this programme will present China with a tough challenge.

Market in Kota Baru, Malaysia

The World Bank, for example, has estimated that power stations totalling about 18,000 MW in installed capacity will need to be built over the next 10 years to maintain the targeted 5% share of renewable energy in the power supply mix.

Wind power also offers considerable potential in China where the installed wind power capacity is estimated not to exceed 1,000 MW, compared with the country's huge estimated 160,000-MW wind power potential. Although China plans to install 1,190 MW of wind power in the Tenth Five-Year Plan, some observers consider the target too ambitious due to the small size of wind power units and the large number that need to be installed to achieve the target.

As part of efforts to support wind power development in China, the ADB has approved a $58mn loan to cover the foreign exchange costs of building three wind farms totalling 78 MW installed capacity that are due to be connected to regional power grids. Apart from reducing pollution in their localities and providing additional power output, the three wind power projects are expected to serve as template projects to help China in planning and constructing other grid-connected wind farm schemes in the future.

However, following approval of the loan, the Chinese government decided to revise wind energy tariffs and reduce them to below the level that the ADB felt was the minimum needed for the project to be economically viable. Consequently, discussions continue over appropriate tariff levels before the project can move ahead.

The ADB's involvement in helping China develop biogas from agricultural waste has been more successful, supported by a $33mn loan for a biomass-based renewable energy project to solve farm, farmyard and farmers' household waste disposal problems. China generates over 600mn t/y of biomass waste from agriculture, of which about 1mn t/y is burned in open fields – creating atmospheric pollution.

The project involves helping farmers in Jiangxi, Hubei, Henan and Shanxi provinces to build greenhouses covering 0.07 hectares, comprising a pigpen with a biogas digester and covered land area to grow horticultural crops. Household, farm and animal wastes are channelled into the digester, which, on fermentation, produces year-round biogas – volumes are sufficient for sale to nearby villages through small pipelines for use in homes for cooking and water heating. In addition, the organic fertiliser produced is available for use on the farm and greenhouse crop production.

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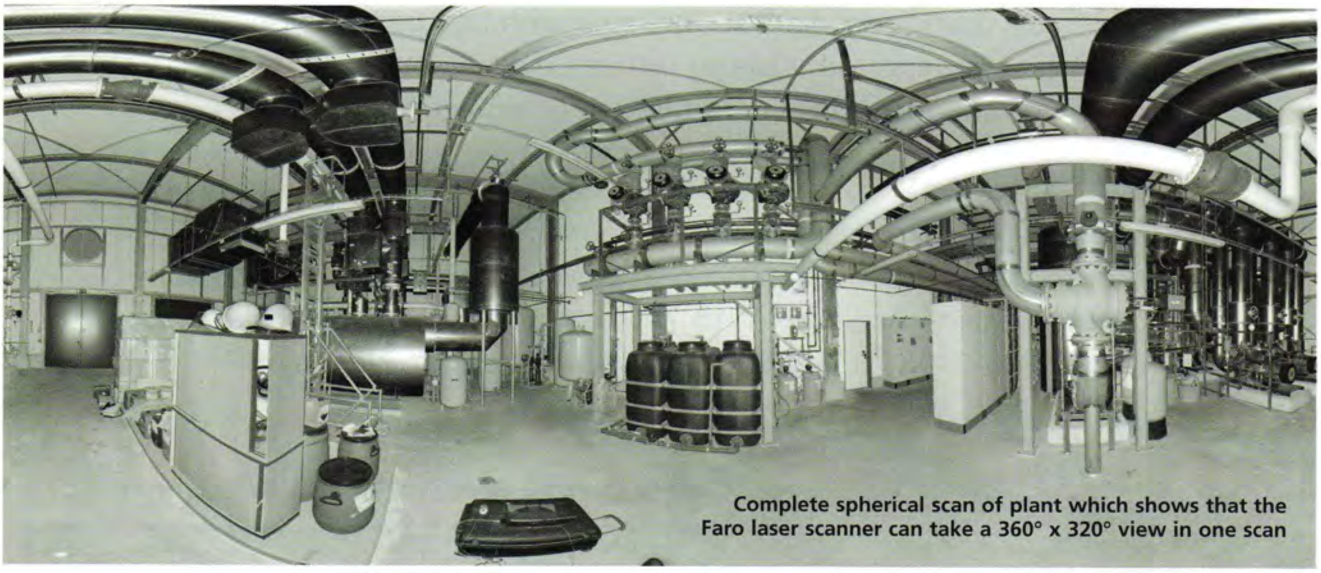
Colour scan of Duisberg power plant

The next dimension in digital photography

The Laser Scanner LS is the latest product in the Faro range. Claimed to be the 'ultimate in large-scale, non-contact measurement', the scanner is capable of taking 120,000 points per second in a full 360° horizontal and 320° vertical envelope, with 3mm linearity error at 10 metres, to generate high quality point cloud data in a matter of minutes. Scans can be displayed in 2D or 3D, black and white or colour, and can be exported to CAD. Kim Jackson *reports.*

Faro Technologies and its international subsidiaries design, develop and market software and portable, computerised measurement devices, allowing manufacturers to perform 3D inspections of parts and assemblies on the shop floor. This, they claim, helps eliminate manufacturing errors, increasing productivity and profitability.

The new Laser Scanner LS is modular in design, made up of four separate component parts – a base module, PC module, laser and distance sensor module, and a mirror



Complete spherical scan of plant which shows that the Faro laser scanner can take a 360° x 320° view in one scan

energy INSTITUTE

Contingency planning for pandemic flu

Monday 17 October 2005 10.00–1600

Energy Institute, 61 New Cavendish Street, London W1G 7AR

Members: £175.00 (£205.63 inc VAT)
Non-members: £230.00 (£270.25 inc VAT)

Pandemics of influenza have swept the world throughout history, causing widespread illness, deaths and societal disruption. It is not known when the next influenza pandemic will occur, but when it does the consequences are expected to be serious, with around a quarter of the population affected, and with over 50,000 deaths in the UK alone. The energy industry is part of the UK's critical national infrastructure, and as such is planning for such an event. The purpose of this conference is to discuss issues and potential problems that industry will face in the event of a pandemic.

Topics covered will include:

- Overview and historical perspective
- UK national contingency plans
- Vaccine development and antiviral development and supply and distribution
- Impact on business and business continuity
- Specific issues relating to the energy industry
- Learning from exercises/experiences from SARS
- The international perspective

Confirmed speakers:

- Dr Charles Easmon, Medical Director, Number One Health
- Paul Werbiski, Director, Health, Safety and Environment, Centrica North America
- Geir Suerre Braut, Deputy Director General, Managing Director, Norwegian Board of Health
- Dr Doug Quarry, International SOS
- Dr R Lambkin, General Manager, Retroscreen

This conference should be attended by health professionals, contingency planners, government and local authorities, health agencies and all those working in industry and responsible for contingency planning and business continuity.

To register your interest please contact: Arabella Dick
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module. These components can be exchanged or upgraded (for example, long range or high accuracy modules) at any point in time, allowing the user flexibility to tailor the scanner to the application. The device is compact, with sealed units, button push operation and can be geo-referenced, making its suitable for daily operation in difficult environments.

According to James Needham, Business Development Manager for Faro Europe: 'The addition of the Laser Scanner LS, while still remaining complimentary to our current products, takes Faro into the broader market of computer aided measurement. The quantity of data that can be captured in such a short time enables new applications, in new markets such as surveying and forensics, for both 3D documentation and CAD-based inspections.'

How it works

The laser scanner works by sending an infrared beam into the centre of a rotating mirror, which deflects the laser around the environment being scanned. Upon contact, the beam is then reflected back in to the scanner and the 'phase shift' of the infrared is measured, giving the distance of the laser from the object. Using encoders to measure the mirror rotation and the horizontal rotation of the laser scanner, the x, y, z coordinates of each point can be recorded.

The main advantage of the phase shift technology is the speed of point capture, 120,000 points per second – up to 100 times faster than conventional 'time of flight' based technology, explains Needham. This reduces the time needed for capturing data on site, increasing the efficiency and profitability of the process. The scanner is also capable of recognising the luminosity of the reflected surface, which builds a grey scale image similar to a 3D black and white photograph. The addition of 'colour option' software enables scans to be coloured, adding another dimension to the realism of the images. This can prove particularly useful in complex environments where, for example, identification of specific pipes or ducts can be made easier.

The laser scanner is linked to Faro Scene software, where settings for the scan can be altered – ie resolution and scan speed. With the click of one button, the scan will begin and the captured data displayed live on screen. In order to capture objects out of the line of sight of the laser scanner, registration spheres can be placed within the area to be scanned and the device moved to different positions and scans taken from the different viewpoints. Once complete, the registration spheres can be recognised within different scans, and the scans linked together to complete the 3D image.

The Laser Scanner LS is claimed to be the 'ultimate in large-scale, non-contact measurement'

Once the scan is complete, the user can navigate the image in 2D or 3D views, literally flying through the point cloud data, in order to make basic measurements. A quick view is also possible from the scanner's perspective.

VRML (virtual reality modelling language) data can be imported into the point cloud to assess, for example, the potential collision risk of new structures in existing plant layout. Faro Scene software also enables tomography (cross-sections), data filtering and allows the user to export data in different CAD formats such as IGES, DXF and AutoCAD. Basic features such as planes and pipes can be recognised and several scans can be registered, allowing multiple views of a scanned environment.

Tip of the iceberg

Up to now the laser scanner has been used for factory planning, facility lifecycle management, quality control, forensic analysis and generally processing large volumes of 3D data. The technology is simplifying and speeding up modelling, while maintaining the required accuracy. The resulting data can be used with major CAD systems or Faro's own software for modelling and designing new factories or redesigning existing layouts.

Needham comments: 'The exciting possibilities opening up to Faro with the introduction of the Laser Scanner LS are just the tip of the iceberg, as the application spectrum for the scanner is seemingly limitless – ranging from examining collision risks when installing new equipment in a production environment to documenting oil platforms or ancient monuments. This is the next dimension of digital photography'.

*For more information, visit **www.faro.com**

Left: Part of an HVAC system in an automotive plant, showing a number of pipes that have been scanned in a point cloud
Right: 3D model derived from scan

ei awards 2005

25 November 2005, the Savoy, London, UK

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The 6th EI Awards ceremony will take place on Friday 25 November at the Savoy, London, hosted by Sir Ranulph Fiennes Bt OBE, described as the 'Worlds Greatest Living Explorer' by the *Guinness Book of Records*.

The EI will present awards to the winners of nominated projects in the categories of Communication, Community Initiative, Environment, Innovation, International Platinum, Outstanding Individual Achievement, Safety and Technology. The evening begins with a welcome drinks reception in the Savoy's River Room. The Awards presentation ceremony follows a gala dinner and proves to be a truly international industry event.

Guest speaker and presenter 2005

Sir Ranulph Fiennes Bt OBE

Ranulph Fiennes was born in 1944, spent his early years in South Africa and was educated at Eton. He followed his late father's footsteps and served with the Royal Scots Greys before joining the SAS. In 1968 he joined the Army of the Sultan of Oman and in 1970 he was awarded the Sultan's Bravery Medal. Since 1969, when he led the British Expedition on the White Nile, Sir Ranulph has been at the forefront of many exploratory expeditions. Dubbed the 'World's Greatest Living Explorer' by the *Guinness Book of Records*, his expeditions around the world include Transglobe, the first surface journey made around the world's polar axis, which took three years to complete, several unsupported North Polar expeditions and the discovery in 1991 of the lost city of Ubar. In 1993 Sir Ranulph and Dr Mike Stroud entered the history books when they completed the first unsupported crossing of the Antarctic continent. For 97 days the pair fought through pain, starvation and snowblindness to achieve this, the longest unsupported polar journey in history. Later that year they were both awarded an OBE (Order of the British Empire) for 'human endeavour and charitable services'.

Despite suffering a heart by-pass operation just 4 months previously, Sir Ranulph's pioneering spirit led him to complete a punishing schedule of seven marathons, in seven days on seven continents in 2003, again with Dr Stroud. First stop was Patagonia at the southern tip of Chile, then the Falkland Islands, Sydney, Australia, on to Singapore, before returning back to this side of the continent for a 26-mile run in London, Cairo and finally, New York. Sir Ranulph Fiennes – who has certainly lived by his family's motto 'Look for a Brave Spirit' – lives on Exmoor.

To book a table at the ceremony please contact Arabella Dick, t: +44 (0)20 7467 7106,
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Race to find the world's most fuel-efficient vehicle

The 29th Shell Eco-Marathon UK took place at Rockingham Motor Racing Circuit, Northamptonshire, in early July. Over 50 teams from seven different countries took part, all hoping to claim the coveted title of the 'world's most fuel-efficient vehicle' and, in turn, gain an entry in the Guinness Book of World Records. Kim Jackson *reports.*

Under the rules of the Shell Eco-Marathon UK competition, teams from schools, colleges and universities, as well as independent and passionate engineers, can enter vehicles in one of three different fuel classes – unleaded petrol, diesel and LPG. Cars are required to drive at an average speed of at least 15 miles per hour for seven laps (10 miles) around the racetrack near Corby. All vehicles must have three or four wheels and meet precise regulations about wheel and track base size, braking systems, steering and safety. At the end of the seven laps, the amount of fuel used is measured and the fuel-efficiency of the car is then calculated by *Guinness Book of World Records*-recognised Shell Global Solutions' engineers – one of whom was the Energy Institute's very own Bob Hooks (below right), Chairman of the EI North Western and North Wales Branch.

Two hydrogen-powered vehicles also took part in the event. However, due to the complexities in fairly comparing the fuel efficiency of this 'future fuel' with more conventional liquid fuels, their results were not included in the overall leader board. However, as Norman Koch, organiser of the Shell Eco-Marathon UK explained, it is hoped that a comparable measurement method will be ready for next year's event – when biofuel-powered vehicles could also take part.

The best Shell Eco-Marathon vehicle designs consider aspects of aerodynamics, rolling resistance, engine efficiency and driving techniques to achieve the highest fuel economy and each year the teams demonstrate creativity and innovation to make the leap required to improve their performance.

Over the years, the fuel economy record has been rapidly improving. The most recent record was set by team Fancy Carol from Japan (set in 2004), who achieved a fuel consumption figure of 11,195 miles per gallon (mpg) using a special Shell fuel similar to Shell Optimax (produced using the same techniques as when Shell mixes fuel for the Ferrari Formula One car). With such efficiency it would be possible for the winning Shell Eco-Marathon UK car to travel three times around the equator on the same amount of fuel that Concorde needed to reach the end of the runway!

Encouraging the engineers of the future

A new Shell Eco-Marathon UK Schools Initiative, supported by the Learning Grid, The Royal Academy of Engineering and Honda (UK), was launched at this year's competition. The programme is specifically designed to encourage secondary schools throughout the UK to include engineering in the delivery of the school curriculum.

The emphasis is placed on pupils between 11 and 14 years – the challenge being to design, build and compete with their own car in the 2006 Shell Eco-Marathon UK, scheduled for 12–13 July 2006, at Rockingham.

A total of 20 schools will be chosen to benefit from a free Shell Eco-Marathon starter pack to help them get the project under way. The pack will include a 4-stroke GX31 engine supplied by Honda (UK), a design and build manual, and an introduction to a locally based engineering company who will assist and mentor the project.

In line with the Royal Academy of Engineering's 'Best Programme' and its work to widen participation in engineering within education, ten of the schools will be selected because they do not have an engineering background. The other ten will be chosen from schools that have expressed previous interest in the event.

Commenting on the programme, Professor Matthew Harrison, Director of The Royal Academy of Engineering Best Programme said: 'The Shell Eco-Marathon's Schools Initiative will encourage UK secondary schools to enter the competition, highlighting the wide range of career opportunities in engineering. It will demonstrate that engineering can be fun and can make a difference to the world we live in by producing cars with world beating fuel economy. I'm sure the initiative will spark an interest in engineering for creative young people who will get the rare opportunity to conceive, design, build and operate their own 21st century vehicle.'

With weight (mass), or lack thereof, being such a key factor in the search for fuel efficiency, contestants as young as 11 had the opportunity to get in some early motoring experience on the high-speed turns of the Rockingham race track.

Fierce competition

Competition for the 2005 Shell Eco-Marathon UK was very tough. However, poor weather conditions meant that the current world record remained unbroken. At the end of the competition, Microjoule of France took the honours – with a final fuel (gasoline) consumption of 8,263 mpg (miles per gallon). In overall second place was TIM 03 (also from France) – 6,913 mpg (gasoline); third place going to Les Vieux de La Jol (France) – 5,087 mpg. The top British entry was Team Green from Somerset, with 4,866 mpg (gasoline).

In the University Class, first place went to Team Callo (France) – 4,795 mpg (gasoline), followed by PV3e (France) – 4,718 mpg (gasoline), and Energyteam Belgium (Belgium) – 3,861 mpg (diesel). Meanwhile, the Autocar Schools Class was won by Intercop (Twickenham, UK) – 1,336 mpg (gasoline), with second place going to Flying Scotstown (Aberdeen, UK) – 867 mpg (gasoline) and third TSR 3 (Croydon, UK) – 688 mpg (gasoline). The best fuel consumption by an LPG vehicle was 3,011 mpg, built by Team Green (Somerset, UK), while DTU Roadrunners' (DTU, Denmark) hydrogen-powered entry came in at 2,017 mpg.

Highlight of the day

A special highlight of the event for competitors and spectators alike was a visit by 7-time Formula One World Champion, Michael Schumacher and his Scuderia Ferrari team mate Rubens Barrichello, who visited the race track en route to the British Grand Prix. They took time to meet the record-breaking engineers of the future and even took a turn around the track in Shell's own custom-built Eco-Marathon car – Schumacher achieving a fuel consumption figure of 454 mpg and Barrichello 331 mpg. I myself had the opportunity to test my driving skills in the Shell vehicle. I finished with a final figure of 371 mpg – beating Barrichello... who, I suspect, just couldn't resist being the quickest, and hence least fuel-efficient, around the track!

Before being whisked off by helicopter to the Grand Prix, Schumacher commented: 'What the teams and Shell are doing here at Rockingham is amazing. It sounds unbelievable how little fuel is used to get the cars to travel such a distance. I am told that if we used a Shell Eco-Marathon car on Sunday [British Grand Prix] I would be able to drive three World Championships without stopping for fuel, that would certainly give us a great competitive advantage – it may not be too fast, but I wouldn't have to make many pit stops!'

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The Queen's Awards for Enterprise: International Trade 2004

TransTrain success

Nicholl Oils, the Northern Ireland-based fuel distribution company, achieved a 100% pass rate for its operatives at a recent TransTrain training course held at BP Oil's Kingsbury terminal, Warwickshire.

Based in Londonderry and an authorised Texaco distributor, Nicholl Oils operates 48 vehicles for a combination of urban and trunking work throughout Ireland. Commenting on the TransTrain course, Colin Nicoll said: 'Although we've been operating for 40 years and would like to think that there's not a lot that we don't know about this business, we feel it is very important to keep in tune with the latest in terms of practice and procedure in the maintenance and safe operation of petrochemical tanks.'

'Two of our engineers attended the 3-day course and have come away with an industry-recognised qualification, which has served as a helpful refresher on the one hand and an important reassurance to our customers on the other.'

The TransTrain course, which covers all aspects of safety, maintenance, testing and general procedures concerning petroleum road tankers, ensures that operatives at every level of involvement with petrochemicals do not put themselves, their company or others at risk. Each of the successful candidates, which included employees from MAN-ERF, West End Garages & Heil International Trailers, will receive a certificate endorsed by the SOE and Energy Institute, and will be placed on a national register noting their qualification.

'All in all,' concludes Nicholl, 'when it comes to safety, you can never have enough training. This high calibre course, however, covers all the stops and gives us a broader understanding of running maintenance and repairs into the bargain.'

The training course is offered in two modules. Module A (one-day) costs £250.00 for 1 delegate, £233.00 each for 2 delegates, and £217.00 each for 3+ delegates.

Module B (three days) costs £750.00 for 1 delegate, £700.00 each for 2 delegates, and £650.00 each for 3+ delegates.

There is an additional cost of £120.00 per delegate for an IRTE certificate on each module.

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Turnkey environmental testing of water/soil

Recent legislation in many European countries and in the US has made the determination of the content of mineral oils and petroleum products in water and soil a compulsory requirement for quality certifications.

Recognising the need for stricter environmental analyses, Thermo Electron has developed new turnkey solutions in order to help environmental laboratories, government agencies and water suppliers comply with the requirements of European norm ISO 9377-2.

'Historically, the main analytical technique used for carrying out water and soil quality tests has been infrared (IR), which is well known to require analysts to use possible carcinogens and banned chemicals for the extraction process,' comments Thermo. 'In this light, our GC-FID turnkey solutions, featuring no limitations in the solvent selection, emerge as the only analytical techniques tolerated and supported by the norms for total petroleum hydrocarbon applications. These solutions cover the range C10–C40 in both the water and soil matrices in a user-friendly and reliable way.'

Three complete packages are offered:

- Standard – a cost-effective option based on the conventional GC method.
- Sensitive (LVSL) – which delivers the lowest quantification limit below 0.5 ng/uL of total hydrocarbons.
- Ultra Fast – which boosts productivity, with up to 100 samples processed in a single day.

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Flexi-Drive operates hard to reach valves

The Flexi-Drive from Smith Flow Control is a cable-driven remote operator for valves in inaccessible or hazardous locations. It can transmit drive to valves as far as 60 metres away, accommodating 540 degrees of bends in the cable run.

The cable allows high valve operating torque to be transferred through tunnels, walls, bulkheads, floors or any other obstacles betwen the handwheel and the valve. The Flexi-Drive is available in a range of reduction ratios, including 4:1, 2:1 and 1:1, with no danger of delivering over-torque.

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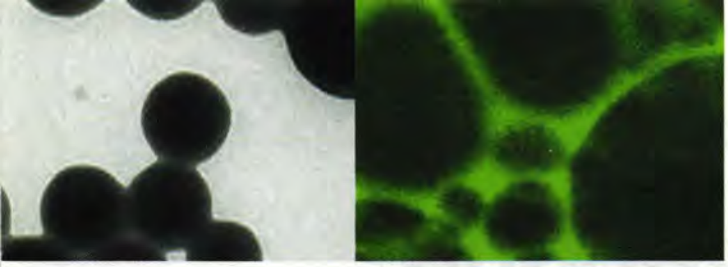

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Is the EU ETS working?

The European Union's Emissions Trading Scheme (EU ETS) has now been in force since 1 January 2005 and a great deal of progress has unquestionably been made during the first six months. John Chennells, *Principal Consultant, Energy & Utilities, LogicaCMG, looks at how the scheme has been performing in the UK, and asks whether it is really achieving what it set out to do.*

The European Union's (EU) ratification of the Kyoto Protocol requires total emissions of greenhouse gases (GHGs) to fall to some 92% of their 1990 levels in the period 2008–2012 and the EU ETS is a key EU policy response to this challenge. Together with companies in four other sectors (refineries, ferrous metals, pulp and paper, and building materials) power generators will be subject to a 'cap-and-trade' system of emissions control. Allowances are determined by national government allocations across the EU (initially based on historical carbon dioxide (CO_2) emissions, but, after 2008, the scheme will be extended to cover the other five GHGs). These allocations are freely transferable between companies or tradeable on the open market, with the objective of incentivising lower cost emissions abatement.

A great deal of progress has been made since the scheme's launch on 1 January 2005. To take just a few examples at the time of writing:

- The national allocation plan for the final outstanding country (Greece) is about to be approved, so the allocations of emissions allowances for all the countries in the EU are now known.
- National registries are commencing operation and companies are now receiving their allowances for 2005.
- Three new climate exchanges were due to open for trading during June – making a total of six in all – offering companies a further option to add to over-the-counter (OTC) and brokered trades.
- The volumes of allowances being traded are gradually increasing, with over 1mn tonnes being traded on some days.
- The exchanges offer opportunities to trade in carbon futures as well as on-the-spot market, and no doubt other types of derivatives trades will follow.
- The trading price of allowances has risen sharply from approximately 7/t earlier in the year to over 20/t in mid-June, on the back of sharp increases in gas and oil prices.

However, does this increase in activity mean that the EU ETS is working, given that its primary purpose (notwithstanding the name) is to reduce overall levels of emissions, rather than to develop a new commodity market?

A mixed bag

In 2004, LogicaCMG commissioned a market research study of the levels of preparedness for the introduction of the EU ETS. The results of this were reported in the July 2004 issue of *Petroleum Review*. A year later, a follow-up study commissioned by the same company suggests that there is still considerable variation in levels of awareness and involvement in the scheme.* Amongst the findings of the latest survey were:

- Approximately one company in five of those interviewed in the UK risks serious penalties as a result of failure to have their emissions verified. While 60% of the companies interviewed have appointed a verifier, 18% not only have not done so – but also have no plans to do so this year. This implies very strongly that these companies simply do not understand that verification is an essential part of the process of surrendering their 2005 allowances; or that the penalty of 40/t will be levied for failure to surrender, not just for exceeding allowances.
- Only about half of the companies interviewed in the UK expect either to buy or sell allowances. While this is a significant increase from the figure of around one-third of the companies interviewed a year ago, it still leaves 26% saying they are unlikely to trade, 18% of 'don't knows' – and, alarmingly, 4% claiming they don't intend to comply. However, the real challenge which this response poses, is that with such a large percentage of the market electing not to trade, it will be very difficult to develop the sort of liquidity that the market needs in order to achieve its principal objective.
- Nearly half of the companies interviewed in the UK have yet to establish procedures for showing the intangible assets (allowances) or liabilities (emissions) on their balance sheets. This is despite clear guidance from the International Accounting Standards (IAS) Board that this is how allowances and emissions are to be treated, in accordance with IAS 38. Failure to comply with the requirements of this standard could leave companies unable to quantify their true financial position arising from their emissions, and hence unable to report accurately to their shareholders.
- Four out of five UK companies interviewed have made no provision for the costs that may be incurred, either as a result of penalties for failure to surrender allowances, or through a need to purchase additional allowances to make up a shortfall. With the market price of allowances continuing to increase, so too is the potential exposure of those companies who have not taken any steps to manage the financial risks presented by the EU ETS.

In a wider context, during the month of May, concerns that the UK government's climate change policy may be in danger of failing were expressed from such disparate sources as the Royal Society, Cambridge Econometrics and the Director General of Energy Policy at the DTI. Critics have called for a significant reduction in emissions allowances if the government is to have any chance of meeting its target of reducing CO_2 emissions to 20% below 1990 levels by 2010. So it is particularly important for the government that the current first phase of the EU ETS should be seen to be a success.

Problems and pitfalls

Arguably, the biggest problem currently facing the scheme lies in the low volumes of allowances being traded. Despite the bullish statements from some of the exchange operators, a daily traded volume of 1mn tonnes of CO_2 is only equivalent to the annual allowance for a single medium-sized gas-fired power station. To put this in perspective, the UK's total annual allowances – which are approximately 10% of the figure for the EU as a whole – amount to some 250mn tonnes. So

What every business needs to know

'In the medium term we will all be emissions traders, either directly or indirectly.' So says a new book entitled *Climate Change and Emissions Trading: What Every Business Needs to Know*, published by the Consilience Energy Advisory Group (CEAG).*

Liz Bossley, CEO of CEAG, Director of the London Climate Change Services group and principal author of the book, points out that: 'Power prices in Europe have already increased to reflect the cost of compliance with legislation to reduce greenhouse gas (GHG) emissions. Power is the engine of economic growth and any factor that impacts its price has a direct influence on the international economy.'

The Climate Change Plan of Action agreed at the G8 summit did little to bring the US into the Kyoto Process, other than achieve recognition that climate change is happening and that human activities are at least a contributory factor. The next opportunity for progress is the Montreal conference of parties to the UN Framework Convention on Climate Change (UNFCCC) in November.

Bossley issues a reminder: 'Although the US will not ratify the Kyoto Protocol, it remains bound to cut GHGs by the fact that it signed the UNFCCC; it is the Kyoto mechanisms and targets to which the US objects.'

All parties to the UNFCCC have agreed, broadly, to:

- Collect and share information on GHG emissions.
- Cooperate to a greater or lesser degree in programmes to mitigate climate change or adapt to climate change.
- Promote the transfer of clean technology.
- Conserve and enhance the management of land, sea and coastal ecosystems.

The US has signed up to the UNFCCC as an Annex I and Annex II party. This commits it additionally to:

- Limit its own anthropogenic, or man-made, GHG emissions.
- Cooperate in achieving a return to levels of emissions experienced in an earlier historic period.
- Provide new and additional financial resources to meet the agreed full costs incurred by developing countries in measuring and communicating their GHG emissions.
- Underwrite, to an extent and in a manner to be agreed, the cost of transferring green technology.
- Provide aid to vulnerable developing countries in adapting to climate change.

So, if President Bush does not like the Kyoto method of achieving these goals, we are all waiting to hear the alternative.

Says Bossley: 'The market has kept its end of the bargain by delivering workable instruments to trade European carbon dioxide (CO_2) allowances. It is now up to the regulators to provide a stable and meaningful framework in which trade can take place.'

CEAG's book examines the development of emissions trading so far and predicts the likely future shape of the market. Bossley believes that the nature of emissions risk for firms lends itself to options-based risk management strategies. 'But,' she points out, 'until we have enough price history to quantify the risks more precisely for the options-modellers, trade is likely to continue to grow based on physical, forward and futures contracts.'

Climate Change and Emissions Trading: What Every Business Needs to Know* is priced at £99.50 and is available from **www.ceag. org/whatsnew.html

the market remains relatively thin, with many companies apparently still preferring to hold on to spare allowances rather than releasing them to cash in at more than 20/t.

The problem that this failure to develop liquidity in the market presents, is that makes it much more difficult to discover the least cost means of abatement. The whole point of the scheme is that trading is intended to be a means to an end, not an end in itself. In a liquid market, trading will take place until the ultimate sellers are the companies that can reduce their emissions at the least cost – thus enabling the reductions targets to be met in the most economically efficient manner. The difficulty with this, however, is that if a liquid market fails to develop, the efficiency of the scheme is significantly impaired.

Another potential pitfall is that discovery of the least cost of abatement has to be allied with investment in the area of abatement itself. And, as recent comments from the EC Director General at the Environment Directorate suggest, the indications are that the timescales of the EU ETS do not match those of business investment decisions. Therefore, it may be that significant investment in abatement cannot be delivered within the first phase of the scheme.

Only six months into a three-year first phase of the scheme, it is, of course, far too soon to say that the EU ETS is failing. However, it is not unreasonable to suggest that there is a real risk that this first phase may fail to meet its targets unless more companies start to become actively involved. The next six months will be crucial.

The full report, entitled* Managing Emissions – Opportunity or Threat? *is available for download (along with the 2004 report) from* **www.logicacmg.com

EI Breakfast Briefing

energy INSTITUTE

Building a low carbon future – 7 September 2005

Tom Delay, Chief Executive of the Carbon Trust

The Carbon Trust is an independent company funded by Government. Its role is to help the UK move to a low carbon economy by helping business and the public sector reduce carbon emissions and capture the commercial opportunities of low carbon. *Tom Delay*, Chief Executive of the Carbon Trust, will give an insight into:

- What a low carbon future means
- How to make the business case internally and externally
- Opportunities to work with the Carbon Trust

Venue: Energy Institute, 61 New Cavendish Street, London WIG 7AR
Time: 07.30: Registration and breakfast
08.00: Speech
Price: Members: £15.00 (£17.63 inc VAT)
Non-members: £20.00 (£23.50 inc VAT)

For more information please contact: Arabella Dick t: +44 (0)20 7467 7106 f: +44 (0)20 7580 2230 e: arabella@energyinst.org.uk www.energyinst.org.uk

Caspian Energy Adviser

Foreign and Commonwealth Office

Circa £70,000 pa

In this important new role, you will ensure the UK meets its international energy objectives in the Caspian region, travelling there regularly in order to help deliver our International Energy Strategy and Country Action Plans.

This will involve forming close partnerships with colleagues throughout the FCO, DTI, Defra and DfiD, as well as senior executives from oil and gas companies and international organisations such as the IEA. You will also need to get to know officials from governments and organisations in the region. In particular, you will be working in support of enhanced energy sector management and more transparent and competitive oil and gas markets.

You will require in-depth knowledge of energy issues in the Caspian region and the political dynamics of the region, backed by proven networking ability within both Government and the private sector.

Fluency in Russian would be an advantage, but is not essential provided you have the skills and capabilities to communicate and actively promote the energy security agenda.

Initially you will be contracted on a two year fixed-term self-employed basis, with the possibility of renewal. Only British Citizens who have been resident in the UK for at least two of the previous ten years, one year of which must have been a consecutive twelve month period, will be eligible to bid for this contract.

If you feel you have the skills for this role and want to work with us in an area of work that is very much rising up the Government's agenda, please contact Tom Franey on (020 7008 3809) for an invitation to tender. Successful applicants will be invited to interview. Closing date for completed tenders: 3 October 2005

Middle East Energy Adviser

Foreign and Commonwealth Office

Circa £70,000 pa

In this important new role, you will ensure the UK meets its international energy objectives in the Middle East region, travelling there regularly in order to help deliver our International Energy Strategy and Country Action Plans.

This will involve forming close partnerships with colleagues throughout the FCO, DTI, Defra and DfiD, as well as senior executives from oil and gas companies and international organisations such as the IEA. You will also need to get to know officials from governments and organisations in the region. In particular, you will be working in support of enhanced energy sector management and more transparent and competitive oil and gas markets.

You will require in-depth knowledge of Middle East energy issues and the political dynamics of the region, backed by proven networking ability within both Government and the private sector.

Fluency in Arabic would be an advantage, but is not essential provided you have the skills and capabilities to communicate and actively promote the energy security agenda.

Initially you will be contracted on a two year fixed-term self-employed basis, with the possibility of renewal. Only British Citizens who have been resident in the UK for at least two of the previous ten years, one year of which must have been a consecutive twelve month period, will be eligible to bid for this contract.

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