MARCH 2005

Petroleum review

IP WEEK 2005
- Lee Raymond: On the cusp of change
- Sir John Collins: Global warming – action or just talk?
- IP Week exhibition review

SEISMIC
- Talking up the reservoir

AFRICA
- North Africa steps on the gas

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Many oil and gas companies are now revising their risk management procedures to establish integrated company-wide approaches or Enterprise Risk Management (ERM). However, the industry as a whole does not have a very good track record in managing or responding to risks and opportunities in an integrated and systematic manner. To be effective in improving corporate performance ERM needs to integrate the many facets of financial, operational and strategic risk and opportunity management in addition to addressing internal control, reporting and compliance issues. This **3-day** course involves oil and gas industry case studies that reinforce the view that the key to effective ERM is implementation of a framework with an integrated, structured and systematic approach across corporate, financial, operational and strategic divisions, involving proven specialised tools, techniques and people.

Who should attend?

This course is designed for a multi-disciplined audience with diverse corporate, financial, technical, strategic planning, risk management and operational backgrounds. Course content addresses issues and skills relevant to professionals working within listed and state-owned oil and gas companies and many support and service sectors to the industry, including: accountants, analysts, asset managers, auditors, bankers, economists, insurers, lawyers, portfolio analysts and managers, public relations managers and consultants.

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Who should attend?

- *Technical, analysts, planners, operating, marketing, support and engineering personnel seeking a broader overview of the sector*
- *Those new to the industry, including graduate trainees, who require a concise introduction to the aviation business*
- *Managers and professional staff from government departments and agencies.*

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Who should attend?

This course is designed for a multi-disciplined audience with diverse commercial, technical, corporate, operations, planning and risk management backgrounds from various sectors of gas and power supply chains. Course content addresses issues and skills relevant to professionals working within companies producing, trading and marketing gas and the many service sectors supporting the industry, including: analysts, asset and portfolio managers, bankers, economists, engineers, gas traders, geologists, insurers, lawyers and risk managers.

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover picture: Lee Raymond, Chairman and CEO, ExxonMobil, speaking at the IP Week 2005 Annual Dinner at the Grosvenor House Hotel, London

All IP Week photos: Jim Four

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IP WEEK 2005

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Was 2004 demand so exceptional?

This year's IP Week was once again a resounding success, with around 2,500 industry executives attending all or some of the events. The two big set piece speeches of the week addressed the complex issue of delivering affordable energy in the volumes required without imperilling the environment we all inhabit.

Lee Raymond, CEO of ExxonMobil – in what was probably his last public appearance in Europe before his retirement – addressed the 1,000-plus guests at the annual dinner, spelling out the size and complexity of the supply challenge facing the industry (see p22). It seems most unfortunate that Greenpeace sought publicity by knocking over bottles of wine (surely a waste of resources!), rather than engaging in constructive dialogue on the complex problem of fuelling the world without damaging it. The day before, at this year's Annual Lunch, Sir John Collins had addressed the progress and the challenges in meeting Kyoto targets for carbon dioxide (CO_2) reduction (see p25). The report on the IP Week exhibition appears on p27 of this issue. Space constraints mean that the report on the conferences will now appear in our April issue, as will the second part of David Wood's feature on upstream contractual frameworks.

It is always difficult to try to encapsulate the tone of a whole week of conferences. The nearest attempt would be 'nervous confidence' – confidence that a whole range of challenges could, in fact, be met, but nervousness that success could easily be derailed. A much repeated *caveat* was that Chinese demand slows down in 2005.

The reason that so many are so nervous about Chinese demand is the sheer speed with which it has been growing. According to the IEA's latest *Oil Market Report* (February 2005), Chinese demand grew by 120 kb/d in 2001, 300 kb/d in 2002, 550 kb/d in 2003 and 860 kb/d in 2004. Demand growth in 2005 is currently estimated at 400 kb/d. The unspoken question in the industry is: 'Is 400 kb/d realistic or wish fulfilment?' – particularly as 4Q2004 saw upward revisions to Chinese demand.

Overall demand in 2004 has also been revised up to 2.68mn b/d. This was the second highest annual increase ever recorded – 1976's record 3.35mn b/d consumption growth and 4.38mn b/d production growth was largely met by Opec turning on 3.5mn b/d of capacity it had turned off a year earlier.

According to the IEA, total Opec production (including NGLs) reached 33.01mn b/d, or 2.34mn b/d, above 2003 production. By December 2004 Opec was producing a record 34mn b/d. At this point the general consensus was that the only spare capacity in the world was around 1mn b/d of Middle East high sulphur crude that was virtually unsaleable because sulphur handling capacity is the bottleneck in global refining; the only other notional space capacity in Iraq, Nigeria and the Gulf of Mexico created by sabotage, political action and hurricane damage respectively.

With quite limited spare capacity, any incremental demand in 2005 will largely have to be met by new capacity coming onstream. In fact, significant volumes of new capacity are due onstream this year, with four out of the 22 major new projects due for start-up in 2005 already onstream. (Our latest fully updated listing of megaprojects will be published in the April issue.) However, although the gross capacity additions in 2005 are quite large, the IEA's view is that net capacity additions will be just under 1mn b/d for non-Opec and up to 1mn b/d for Opec, of which 440 kb/d will be from NGLs.

Clearly, 2005's supply/demand balance is precarious. Opec cutting supply by 770 kb/d in January has kept prices firm, even before the cold weather price boost. Demand estimates are already creeping up, with the IEA now predicting 1.52mn b/d against January's 1.44mn b/d. The major supply side risks are that Russian production growth will be less than the currently predicted 5% and that new projects will be delayed or underperform. The major demand side risks are that Asian and North American demand growth in 2005 will be more than half their 2004 level (the current IEA prediction).

Further downward revisions to SEC definition proven reserves by oil companies continue to spook investors and undermine confidence. Deloitte's Peter Newman and Victor A Burk have written a pamphlet – *Presenting the full picture. Oil and gas: reserves measurement and reporting in the 21st century* – presented during IP Week, which argues that confidence will only be restored once companies print both proven and proven + probable reserves, as well as forward estimates of production flows. Copies of the pamphlet are available from Deloitte – visit **www.deloitte.co.uk**

Chris Skrebowski

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

E-DATA

The Health and Safety Commission (HSC) is seeking views on a draft updated guidance booklet covering the Control of Major Accident Hazards Regulations 1999 (COMAH). The update is necessary because COMAH is being revised to implement a new EC directive, which amends the original Seveso II Directive. The full text of the draft revised guidance can be viewed or downloaded from the HSE's website **www.hse.gov.uk/consult/live.htm**

Houston-based Knowledge Reservoir released in mid-December its latest update for 2004 to 'Reservoir KB', a web-based, deepwater reservoir performance knowledge base for the Gulf of Mexico. The update was issued to the 19 key players in the deepwater Gulf of Mexico who currently subscribe to Reservoir KB and who have cited considerable gains in efficiency as a result of using the tool in their exploration work flow. The Gulf of Mexico module of Reservoir KB incorporates information drawn from 104 deepwater fields in varying stages of development. Included are a number of fields that have been sanctioned for development. The knowledgebase incorporates substantial production data that are used to perform an independent analysis of performance at field, reservoir, and well level. For more information, please visit **www.knowledgereservoir.com**

UtiliPoint® International and Global Change Associates have launched a new web community in support of their ongoing energy hedge fund research and service offerings. For details, visit **www.energyhedgefunds.com**

Sibneft has launched a new version of its website at **www.sibneft.com** which includes new web pages for several of Sibneft's regional marketing subsidiaries, including Sibneft AZS Service (Moscow city and region), Tyumennefteproduct (Tyumen region), Kuzbassnefteproduct (Kemerovo and Tomsk regions), and Ekaterinbergnefteproduct and Sverdlovsknefteproduct (Sverdlovsk region). These pages contain information for retail and wholesale customers on the products and services offered by each affiliate, as well as map locators for service stations. Additional Sibneft marketing affiliates are expected to go online during 2005.

Oxford Instruments has launched a new X-ray microanalysis website at **www.x-raymicroanalysis.com**, that is designed to complement **www.ebsd.com** which went live last year. The new site contains extensive tutorials on EDS and WDS techniques and detectors. It also guides the user simply and easily through the INCAEnergy and INCAWave software.

UK

***Faroe Petroleum has acquired a 90%** equity stake in two part blocks 14/21 and 14/22 in the UK central North Sea from Shell UK Limited and Esso Exploration and Production UK.*

***Rig utilisation in the North Sea dipped** in January to 79.2%, from 81.7% in December, according to the latest data from Platt's* North Sea Letter. *The fall reflects a small number of semi-submersibles coming into port for repairs, while some new starts have been delayed to mid-February. The real strength in the market is demonstrated six months forward, when utilisation is at capacity for semi-submersibles, excluding cold-stacked rigs, and up 9.5% on the month for jack-ups at 95%.*

***Dana Petroleum has increased its stake** in UK North Sea block 210/24a to 26.6% after finalising deals with Shell and ExxonMobil. The block contains the Melville exploration prospect.*

***BP has revealed plans for spending** $2bn on its UK North Sea business in 2005. The company intends to invest $780mn (£435mn) of capital into a range of projects and activities. In addition, $1.2bn (£670mn) will be invested in operating, supporting and maintaining its producing assets. BP's total capital and operating investment in the UK North Sea over the next four years is expected to be over $7bn (£3.9bn).*

EUROPE

***Norsk Hydro has awarded Aker** Kvaerner a NKr265mn contract for reconstruction of the Troll C platform in order to allow it to produce oil from*

Readership questionnaire – and the winners are...

***Petroleum Review* would like to thank all our readers that took the time to fill in and return the readership questionnaire.**

All respondents were entered in to a draw to win one of five Red Letter Days. The lucky winners are:

Robert Cohen, Doug Harris, Roy Kelly, Denis Morgan and E Spearman.

Congratulations!

First production from Mad Dog

BHP Billiton reports that the Mad Dog field, located in 4,300 ft of water in the deepwater Gulf of Mexico, has come onstream, with a nameplate daily capacity of 100,000 barrels of oil (gross) and 60mn cf of gas (gross).

The Mad Dog development consists of a truss spar, equipped with facilities for simultaneous production and drilling operations. Oil from Mad Dog will be transported via the Caesar pipeline, where BHP Billiton has a 25% equity share, to the Ship Shoal 332B platform, where it will interconnect with the Cameron Highway Oil Pipeline System (CHOPS). Mad Dog gas will be exported via the Cleopatra pipeline, where BHP Billiton has a 22% equity share, to the Ship Shoal 332A platform, where it will interconnect with Manta Ray gathering system, and from there to the Nautilus gas transportation system into Louisiana.

BHP Billiton holds a 23.9% working interest in Mad Dog. BP is the operator, with a 60.5% working interest. Unocal owns a 15.6% working interest.

Saipem secures Kashagan contract

Saipem has been awarded the contract for the installation of the offshore facilities system relating to the experimental phase of the Kashagan field development located in the Kazakh sector of the Caspian Sea. The contract was awarded by Agip KCO – operator of the North Caspian Sea Production Sharing Agreement (PSA)* – following an international tender and is valued at $286mn.

The scope of work includes the fabrication, assembly, transport and installation of 45 piles and two flares, with a total weight of some 15,000 tonnes, along with the installation of 16 module barges. The piles and flares will be fabricated in the newly developed Ersai yard located in the Kuryk area of Kazakhstan, a yard in which Saipem has a participation of 50%. The scope of work also includes the procurement, fabrication and installation of associated mooring and protection structures.

The installation activities, which are scheduled to complete during 2007, will be carried out using a new purpose-built construction barge.

**The companies of the North Caspian Sea PSA, which includes the giant Kashagan field, are: Eni (operator 16.67%), BG Group (16.67%), ConocoPhillips (8.33%), ExxonMobil (16.67%), Inpex (8.33%), Total (16.67%), Shell (16.67%).*

First gas from Minerva project

BHP Billiton has brought onstream the Minerva gas field off Victoria's southwest coast, Australia. The $225mn project had been due to be commissioned in early 2004, but was delayed because of contractual changes relating to the plant's construction. BHP has a 10-year agreement to supply gas from Minerva to the Pelican Point power station in South Australia, a subsidiary of British utility company International Power. The gas is delivered via the 680-km SEAGas underground pipeline, which links Port Campbell in Victoria to Adelaide.

The Minerva development is BHP Billiton's first greenfield gas project in Victoria since it joined with Esso in the 1960s to develop its Bass Strait operations. BHP Billiton holds a 90% interest in Minerva, which has estimated proven gas reserves of 301bn cf. The remaining 10% share is held by Santos.

EnCana to sell GoM and Ecuador assets

EnCana is planning to sell several conventional oil and gas properties – including its Gulf of Mexico holdings – as part of a programme to focus more on natural gas and Alberta's oil sands.

Its Gulf of Mexico assets include an average 40% working interest in 239 blocks comprising about 1.4mn acres and a 25% working interest in the ChevronTexaco-operated Tahiti discovery, one of the largest discoveries in the deepwater Gulf of Mexico to date. Other assets being sold include 15 conventional properties primarily in central and southern Alberta, which collectively produce about 17,700 b/d of oil and natural gas liquids and about 27mn cf/d of natural gas. Three natural gas gathering and processing properties in the Rocky Mountain states are also to be sold – at Fort Lupton and Dragon Trail in Colorado, and Lisbon in Utah. The gas plants have a total processing capacity of 210mn cf/d; each has extensive gas gathering pipelines.

EnCana is also selling Ecuador assets that include interests in five Oriente Basin blocks, plus an interest in the OCP Pipeline.

the Fram East satellite field from October 2006.

UK Energy Minister Mike O'Brien met *with his Norwegian counterpart Thorhild Widvey in early February to mark the conclusion of detailed negotiations on the UK/Norway Framework Treaty, paving the way for unprecedented cooperation on North Sea projects between the two countries. A full copy of the UK/Norway Framework Treaty can be found at the DTI website* **www.og.dti.gov.uk/upstream/infrastructure/nfa_2005.doc**

Shell is to acquire from Statoil a 6.45% *shareholding in the Kvitebjoern field and the Kvitebjoern oil pipeline. The production licence also contains the Valemon discovery that was declared commercial in 2004. Shell will divest to Statoil its minority interests in four production licences, and the Norne gas transport system.*

Statoil has concluded a number of *agreeements on the purchase and sale of licence interests that will simplify development and operation of its Skinfaks field in the North Sea. Plans call for Skinfaks to be tied back to the Gullfaks C platform on the Statoil-operated field. First production is expected in November 2006.*

The Norwegian government has *announced Awards in Predefined Areas 2005 (APA 2005), which includes an important expansion of the predefined areas. A total of 192 blocks or parts of blocks are available, with 41 non-licenced blocks or part blocks resulting from the area expansion. The deadline for submission of applications is noon on 30 September 2005. The awards are planned to take place in December 2005. For more information, visit* **www.npd.no**

EASTERN EUROPE

Poland's gas monopoly PGNiG plans to *increase gas production to 5.5bn cm in 2007, up from 4.3bn cm in 2004, reports* Stella Zenkovich. *Oil production is expected to rise to 1.5mn tonnes in 2007, up from 625,000 tonnes in 2004. The company increased gas production by 6.7 % in 2004 against 2003, while oil production rose by 25 %.*

Georgia plans to triple oil production *to 300,000 tonnes in 2005, according to Guram Varshalomidze, General Director of state-run oil company Gruzneft. Foreign investment will drive the increase, reports* Stella Zenkovich.

Shell and Apache agree farm-out deals

Shell and Apache have signed a series of farm-out deals to drill two firm, plus one contingent, exploration wells and have agreed in principle a third firm exploration well near the Shell-operated Nelson and Apache-operated Forties field in the central North Sea.

Under the terms of the agreement, Apache will operate the blocks and firm exploration wells are planned for block numbers 22/6a, 22/7 and 22/12, with a contingent well possible for block 22/11. Block 22/6a is held 50:50 by Shell and Esso Exploration and Production UK, while blocks 22/7, 22/11 and 22/12a were acquired by Shell as part of the Enterprise Oil portfolio in 2002. Block 22/7 is held by Shell and joint venture partners including BP.

Shell recently drilled an exploration well for Apache in 22/12a, taking advantage of an available Shell contracted rig slot in November 2004 and the results will be announced separately. Apache is expected to start drilling the second and third exploration wells in 1Q2005.

Arthur onstream

ExxonMobil subsidiary Mobil North Sea Limited (MNSL) has produced first gas from the Arthur field in southern North Sea block 53/02. The field is a subsea development tied back to the existing ExxonMobil-operated Thames platform. The produced gas is exported via the existing pipeline to the Bacton terminal.

The project is expected to produce at gross rates of up to 110mn cf/d, with an ultimate recovery estimated at 130bn cf (gross). The field may eventually comprise up to three development wells connected to the Arthur manifold.

The Arthur 2 well is to be spudded in the near future and a potential third well may be drilled later in 2005.

MNSL is the operator of the field, holding a 70% interest. Co-venturer EOG Resources holds the remaining 30%.

Pertra sold to Talisman

Petroleum Geo-Services (PGS) has signed an agreement to sell for $155mn its wholly-owned oil subsidiary Pertra to Talisman Energy (UK), allowing PGS to concentrate on its oil service business with strategic focus on geophysics and floating production operations.

In addition, as a part of the transaction, Talisman has undertaken to split the upside from the Varg field with PGS on a 50:50 basis if revenues exceed $240mn/y in 2005 and 2006, respectively. Further, Talisman and PGS have agreed to an option for Talisman to change the termination clause in the contract between PL038 and PGS production related to the FPSO *Petrojarl Varg* which is producing the Pertra-operated Varg field. Pertra is the operator of PL 038 with a 70% interest, while co-venturer Petoro holds the remaining 30%.

US funding to help Egyptian energy shift

The Overseas Private Investment Corporation (OPIC) has made a commitment to provide $300mn in political risk insurance to Apache Corporation that is to help Egypt shift the emphasis of its energy production from oil to more environmentally-friendly natural gas. Apache, reportedly the largest US investor in Egypt, will use the OPIC insurance to develop various onshore and offshore oil and gas concessions in the country.

Apache's natural gas discoveries in the Western Desert have already played a significant role in helping Egypt to convert much of its thermal power generation capacity from oil to natural gas, and in providing the resources necessary to meet growing local energy needs as well as expanding Egypt's hydrocarbon exports. Egypt's production of crude oil from maturing oil fields is declining, while large discoveries of gas have emerged in the Western Desert and Nile Delta.

'The oil and gas sector is an increasingly important part of the Egyptian economy, accounting for 8% of the country's gross domestic product,' OPIC President and Chief Executive Officer Dr Peter Watson said at a signing ceremony at OPIC headquarters. 'Apache's continued investment in the sector will be critical to Egypt's ability to meet both domestic and export demand.' Dr Watson also noted that Apache produces 14% of Egypt's total oil and gas output and, according to company estimates, generates nearly $4mn/d in net revenue for the Egyptian economy.

OPIC was established as an agency of the US government in 1971. It helps US businesses invest overseas, fosters economic development in new and emerging markets, complements the private sector in managing risks associated with foreign direct investment, and supports US foreign policy.

IN BRIEF

***Falcon Oil & Gas, operator (28.75%) of** the Brodina concession onshore northern Romania, reports that the Bilca-2 well is to be completed as a gas producer. Partners are SNGN Romgaz (37.5%), Europa Oil & Gas (28.75%) and Millennium International Resources (5%).*

NORTH AMERICA

***Canada's Nova Scotia has accepted a** deal from its federal government, which should see offshore oil and gas projects funnel C$1bn into the province's treasury over 16 years and guarantee existing federal development grants, reports* Monica Dobie.

***Norsk Hydro is to take over as operator** of the Champlain field, Atwater Valley block 63, in the Gulf of Mexico, after acquiring a 57.5% interest in the block via recent acquisitions. As the new operator, Hydro has selected a new name for the project – TelemarK.*

***The US government is reportedly** planning to open for exploration drilling thousands of acres on Alaska's North Slope. The government estimates the area contains about 2bn barrels of economically recoverable oil and 3.5tn cf of natural gas. The NPRA is not to be confused with the Arctic National Wildlife Refuge which is located farther to the east.*

***Canadian Natural Resources has** awarded Technip two contract worth some C$1,070mn for upgrading facilities and a hydrogen unit for the Horizon oil sands project in northern Alberta, Canada.*

MIDDLE EAST

***The state-run Gas Authority of India** Limited (GAIL) and Indian Oil Corporation (IOC) have signed an agreement with National Iranian Gas Export Corporation to import 7.5mn t/y of LNG over a 25-year period, reports* Stella Zenkovich. *In addition, India's state-run Oil and Natural Gas Corporation's (ONGC) overseas arm has entered into an agreement with the National Iranian Oil Company (NIOC) to take a 20% stake in Iran's Yadavaran field and an unspecified stake in the Jufeyr field.*

***Russia and Syria are to sign agree**ments on the participation of Russian companies in various Syrian oil and gas project developments, writes* Stella Zenkovich.

NEWS

UK output up on month/down on year

UK oil production in November 2004 saw an increase of 6.4% on the month, reaching 1,734,630 b/d, according to the latest (January 2005) Royal Bank of Scotland *Oil and Gas Index*. However, this was down 14.8% on the year.

Gas production was up 4.8% on the month, at 10,395mn cf/d, but down 17.8% on the year. The significant downturn in gas production is related to the mild November, states Royal Bank.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Nov 2003	2,036,012	12,641	28.76
Dec	2,056,469	12,642	29.84
Jan 2004	2,014,906	12,689	31.12
Feb	1,972,891	11,220	30.89
Mar	2,006,160	11,787	33.72
Apr	1,964,905	12,181	33.36
May	1,778,979	9,218	37.72
Jun	1,776,246	10,192	35.21
Jul	1,758,312	10,292	38.15
Aug	1,621,582	8,585	42.99
Sep	1,526,692	8,726	42.92
Oct	1,630,230	9,921	49.66
Nov	1,734,630	10,395	42.88

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

UK offshore statistics for 2004

Figures released by UKOOA show that investment in the UK's offshore oil and gas industry rose in 2004 and will continue to rise in 2005 and beyond. The outlook on production is also optimistic with UKOOA projecting a 2% increase in oil and gas volumes out to 2010 compared with previous forecasts. The *UKOOA 2004 Activity Survey* is an analysis of data collected jointly with the Department of Trade and Industry in the last quarter of 2004. It reflects the production and investment plans of the 31 leading oil and gas companies producing oil and gas in the UKCS. Its key findings are:

- Total expenditure in 2004, including operational, exploration and capital costs, is an estimated £8.9bn, up £0.5bn on 2003.
- Total expenditure for 2005 is expected to exceed £9bn; total spend over the next five years will be £35bn.
- Capital investment picked up significantly in the second half of 2004, and is projected to remain strong in 2005 at £4.31bn (up 11% on 2004).
- However, operating costs rose sharply last year, by £0.5bn to £5bn; unit operating costs in 2005 are predicted to rise by 18% compared with last year's survey, reflecting the increased costs of extending the life of ageing assets and infrastructure.
- Oil and gas production in 2004 is estimated at 3.8mn boe/d, or 1.38bn boe over the year.
- The production forecast out to 2010 is up 2% on last year's projections, halving the rate of decline in UK oil and gas production to 7%/y. For oil/liquids the survey shows a 4% increase over recent forecasts.

Opec to abandon price band of $22–$28/b

Opec has agreed to keep its output ceiling of 27mn b/d unchanged after its latest meeting in Vienna, stating that there was little sign that oil prices were stifling world growth. However, the cartel refused to rule out a cut in quotas later in the year, saying it might hold emergency talks ahead of a planned meeting in Iran in March.

In an unexpected move, Opec also announced plans to abandon its old price band of $22 to $28/b, stating that: 'Prices have remained outside the band for over a year due to market changes that have rendered the band unrealistic.' While the cartel said it had no plans to set another target, reported comments from some ministers indicate an informal objective of close to $40/b.

In the past seven years, eight oil fields *and 11 gas fields have been discovered in Iran, according to Mahmoud Mohades, a senior NIOC official, writes* Stella Zenkovich.

BP is reported to have won a contract *to study the possibility of increasing production from Iraq's Rumaila oil field in the south of the country.*

RUSSIA/CENTRAL ASIA

The Russian government is reported to *be planning to auction off some 38 oil and gas fields in Eastern Siberia in 2005. The assets to be sold include the Chayandinskoye oil and gas field in Yakutia, with recoverable reserves of 1.24bn cm of gas and 50mn tonnes of oil. The starting price for Chayandinskoye is expected to be at least $100mn.*

The Azerbaijan International Operating *Company (AIOC), operated by BP, has announced the start-up of oil production from the Central Azeri development, part of the Azeri-Chirag-Gunashli (ACG) field, in the Azerbaijan sector of the Caspian Sea. Located in approximately 128 metres of water, Central Azeri (CA) production began from the first of ten pre-drilled production wells on 13 February. Production will increase through 2005 as the other pre-drilled wells are brought online, prior to further platform drilling over the coming years. Total production from Central Azeri is forecast to be some 35mn barrels of oil in 2005 (equivalent to an average of 93 000 b/d).*

Russian oil production is forecast to rise *by about 5% in 2005, reaching between 485mn and 490mn tonnes, Federal Energy Agency head Sergei Oganesian is reported to have said.*

Vladimir Shkolnik, the Kazakh Minister *of Energy and Mineral Resources, has reported that the members of the Agip KCO consortium have agreed to sell one half of BG's 16.67% share in the North Caspian Kashagan project to the Kazakhstan state for an undisclosed sum.*

ASIA-PACIFIC

CS Mutiara Petroleum – a 50:50 joint *venture company between Petronas and Shell – has made another significant gas discovery in block PM301, off the north-east coast of Peninsular Malaysia. The Bunga Anggerik-1 well encountered four gas zones.*

UAE onshore gas development

Foster Wheeler has been awarded a project management consultancy (PMC) contract by Abu Dhabi Gas Industries (GASCO) for the development of the Onshore Gas Development Project (OGD-III) to increase production of condensate and natural gas liquids (NGLs) at Habshan, Abu Dhabi, UAE. The terms of the award have not been disclosed.

The project, which will be carried out by Foster Wheeler's UK office, is one of the three GASCO projects – the other two being the AGD-II and 3rd NGL Train, Ruwais facilities – in a suite of five integrated projects being undertaken in conjunction with GASCO sister companies ADCO (for gas gathering and re-injection) and TAKREER (for condensate storage and shipping). The whole suite of projects is on behalf of the Abu Dhabi National Oil Company (ADNOC).

The new OGD-III facilities will recover condensate and NGLs from well fluids from the Thamama F gas reservoir. Included in the scope of the contract is a new pipeline for transporting NGLs to GASCO's new NGLs facilities at Ruwais (the 3rd NGL Train project) for further separation into ethane, propane, butane and C5+ product streams. Lean gas will be reinjected back into the reservoir at Habshan. Stabilised condensate will be pumped to the Ruwais facilities of the TAKREER refinery for storage/shipping.

Vetco Aibel secures Alvheim contract

Marathon (65%, operator) and its project partners have awarded a $350mn engineering, procurement, construction, installation and commissioning (EPCIC) contract for the Alvheim development on the Norwegian Continental Shelf to Vetco Aibel of Norway. Vetco will undertake topsides work related to the floating production, storage and offloading (FPSO) vessel, which is a central element of the Alvheim development. First production is expected in early 2007.

In addition to the use of the FPSO, the Alvheim development will include subsea infrastructure consisting of five drill centres and associated flow lines. The development also includes the transportation of produced oil by shuttle tanker, and transportation of produced natural gas to the existing UK SAGE system using a new 14-inch, 24-mile cross-border pipeline.

The Alvheim development comprises the Kneler, Boa and Kameleon fields. Alvheim currently is estimated to contain resources of approximately 180mn boe. Marathon's partners in Alvheim are ConocoPhillips (20%) and Lundin (15%).

Liberia's first international round

Repsol YPF has secured the rights for the exploration and development of block 16 in the territorial waters of Liberia, in the first tender run by the Liberian government ever to accept international bids. Last summer, through direct negotiations with the Liberian government, Repsol YPF was awarded the rights to block 17, which is adjacent to block 16. These two Liberian blocks are next to two other offshore blocks (block 6 and block 7) pertaining to Sierra Leone, for which Repsol YPF has an agreement with the Sierra Leone government.

Repsol YPF, operator of all the blocks, is partnered in the Sierra Leone blocks by Australia's Woodside (50%), who has secured rights for block 15 and with whom Repsol YPF is in talks regarding the possibility of jointly exploring the blocks awarded in Liberia. Initial plans for the Liberian blocks include the shooting of 400 km of 2D seismic and 1,600 sq km of 3D seismic, within an initial exploration period of four years.

Mutineer-Exeter ahead of schedule

Santos reports that the Mutineer-Exeter fields off the coast of north-western Australia are expected to produce first oil in March – several months ahead of schedule and 10% under budget. Initial production is expected to be between 70,000 and 90,000 b/d. The field is expected to produce 15mn barrels in 2005, rising to 19mn barrels in 2006.

Santos has also confirmed a downward revision in Mutineer-Exeter oil reserves. Further drilling during 2004 and early 2005 indicated that the reservoir distribution was more complex than originally interpreted, resulting in total (gross) proved plus probable reserves now being estimated to be 61mn barrels, down from 101mn barrels.

UK

Surging crude oil prices and robust *production from its Russian subsidiary TNK-BP pushed BP's replacement cost profit to a record $16.2bn (an increase of 26% from the previous year). The company rewarded investors by announcing a 26% increase in its dividend to 8.5 cents.*

EUROPE

Shell has reported what is claimed to *be the biggest profit in UK corporate history – posting a full-year profit of £9.3bn ($17.6bn) for 2004. However, the company also cut its estimate of proven reserves by another 1.4bn barrels, or 10% – its fifth downgrade in the past 13 months – to 12.95bn barrels.*

The Norwegian government has sold *100mn shares in Statoil for NKr10.6bn ($1.64bn), reducing its overall stake in the oil company to 71.7%.*

NORTH AMERICA

ExxonMobil has posted a 4Q2004 net *income of $8,420mn, reportedly the highest quarter ever for the group. Net income for the year of $25,330mn was also a record, increasing $3,820mn from 2003. ChevronTexaco reported a 4Q2004 net income of $3.4bn and a record $13.3bn for the year, ConocoPhillips $2.4bn and $8.1bn respectively, Anadarko $405mn and $1.6bn, Apache $507mn and $1.7bn, Marathon Oil $429mn and $1.261bn.*

RUSSIA/CENTRAL ASIA

The Russian government and Rosneft *are reportedly planning to create a joint venture – Moscow Gas Company (MGK) – that will provide gas to thermo-electric power plants in Moscow. The Moscow region is estimated to consume some 30bn cm/y of gas – some 10% of total domestic demand.*

The Russian government has given its *final approval for a major oil pipeline to the Pacific. State oil pipeline monopoly Transneft will build an 80mn t/y (1.6mn b/d) pipeline from Taishet in East Siberia to Perevoznaya Bay in the Pacific Primorsk region.*

Kazakhstan is reported to have begun *reconstruction of the Central Asia-Centre gas pipeline. Energy and Mineral Resources Minister Vladimir*

BG Group to supply LNG to Italy

BG Group has signed a sale and purchase agreement (SPA) for the supply of 3.2bn cm/y (2.4mn t/y) of LNG to Enel, beginning in 2008, at the Brindisi LNG terminal in southern Italy. This supply will initially be sourced from Egyptian LNG Train 2, the output of which was sold in its entirety to BG Group's subsidiary BG Gas Marketing in 2003. Until Brindisi LNG is operational, the production from Egyptian LNG Train 2 – in which BG Group is a 38% shareholder – will be supplied primarily to the Lake Charles LNG importation terminal in Louisiana, US.

At the close of 2004, Brindisi LNG – a joint venture between BG Group and Enel – announced that the engineering, procurement and construction (EPC) contract for the LNG importation terminal had been awarded to a consortium led by Tecnimont, including Mitsubishi Heavy Industries, Grandi Lavori Fincosit, Consorzio Cooperativa Costruttori, Sofregaz and Vinci Construction Grands Projets. The Brindisi LNG terminal will be capable of processing 8bn cm/y (6mn t/y) of natural gas. It is scheduled to begin operating in 2008.

Latest European Union developments

Pressure on oil companies to continue cleansing their fuels of potential pollutants continues to be applied within the European Union (EU), with the European Commission (EC) preparing for the introduction of a new standard 'Euro 5' in 2010, writes *Keith Nuthall*. The EC has advised EU member states to harmonise any tax concessions encouraging the use of diesel cars that are cleaner than the 'Euro 4' emissions standard, (which became compulsory on 1 January 2005). In a working paper, it has suggested that governments award tax incentives for cars emitting 5 mg/km of particulate matter, 80% less than the 25 mg/km maximum under Euro 4. Brussels wants to ensure new tax breaks do not clash from country to country, fragmenting the EU internal market.

In other EU news:

- The Council of Europe Assembly has formally concluded that prosecutions of Mikhail Khodorkovsky and Yukos colleagues went beyond pursuing justice and also aimed 'to weaken an outspoken political opponent, intimidate other wealthy individuals and regain control of strategic economic assets'. This comes as the European Bank for Reconstruction and Development (EBRD) has announced plans to invest up to $40mn into Novatek, Russia's leading independent natural gas producer. This would send 'a clear signal of support to independent producers', said the bank. The International Finance Corporation, of the World Bank, is considering making a similar equity purchase of up to $40mn.
- The EBRD is also planning to lend Georgia Railways $12mn to buy oil tank wagons for its Caucasus lines.
- The European Space Agency (ESA) is working with UK-based Infoterra and WesternGeco to develop a seismic-quality mapping service, using data from a range of satellites to guide land-based sensing for oil and gas deposits. The Earth Observation project previews target (especially submarine) regions' topography and geology.
- The EC is taking Belgium to the European Court of Justice (ECJ), claiming it has failed to comply with directive 2003/17/EC on the environmental quality of petrol and diesel.
- A Commission report has claimed EU gas markets remain subject to 'significant rigidities' usually due to 'continuing lack of integration between national markets', letting 'existing incumbents [to] easily protect their position'.
- Austria and Portugal have been censured by the ECJ for failing to prioritise the re-generation of waste oils, breaking two EU directives (of 1975 and 1987).
- The European Parliament's transport committee has called for a feasibility study into setting up an EU coastguard service that could fight ship-source pollution.

ConocoPhillips makes GoM LNG proposal

ConocoPhillips has submitted an application to the US Coast Guard for the construction of a new offshore LNG regasification facility offshore in the Gulf of Mexico. The proposed Beacon Port Clean Energy Terminal will have a throughput capacity of 1.5bn cf/d of gas. It is anticipated that the first shipment of LNG to the facility could be delivered in 2010.

The proposed terminal is part of a larger effort by ConocoPhillips to meet growing demand for natural gas around the world. The company is developing or has proposed other US regasification facilities in Freeport, Texas, and offshore Alabama. It also has an active liquefaction facility in Kenai, Alaska, as well as others at various stages of development around the world, including Australia, Nigeria, Qatar, Russia and Venezuela.

Shkolnik is reported to have said that the pipeline's capacity amounts to 54bn cm/y, which will be increased to 100bn cm/y in several stages.

China is reported to have lent Russia *$6bn to help the Russian government renationalise Yukos' E&P division, Yugansk. Shortly thereafter Russia's state-owned Rosneft began deliveries of crude oil to China's CNPC via railroad and is reportedly planning to supply some 4mn tonnes in 2005. It is not clear if the two developments are related.*

In addition to increasing gas supplies *from Russia's Gazexport, Kassel-based Wingas is to also buy 1.2bn cm/y of gas from Eni of Italy from 2006 until at least 2019.*

The merger between Russian gas *monopoly Gazprom and state oil company Rosneft has been further postponed until March 2005. The merger was originally to be completed in January.*

ConocoPhillips reportedly plans to *exercise its right to double its stake in Russia' Lukoil to 20%.*

ASIA-PACIFIC

Boustead Holdings is reported to have *reached agreement to acquire for $120mn a 70% stake in BP Malaysia, in which Lembaga Tabung Angkatan Tentera (LTAT) holds the remaining 30% share.*

Shell reports that Korean gas company *Kogas has selected Shell joint venture projects – Sakhalin II and Malaysia LNG – as suppliers of up to 4mn t/y of LNG to Korea over 20 years, beginning in 2008.*

AFRICA

Total has announced that the Yemen *LNG Company has signed three heads of agreement (HoA) for the sale of LNG. The first HoA, signed with Tractebel EGI (Suez), covers the purchase of 2.5mn t/y of LNG, while the second, signed with Total Gas & Power, is for the sale of 2mn t/y. LNG from both sales is destined for the US, beginning in 2009 for a duration of 20 years. The third HoA, signed with Kogas, is for the purchase of between 1.3mn and 2mn t/y of LNG by Korea, starting end-2008 and for a period of 20 years.*

Disclosing greenhouse gas emissions

The World Economic Forum's Global Greenhouse Gas (GHG) Register and the Carbon Disclosure Project (CDP), a collaboration of more than one hundred investors with over $17tn in assets, has announced a partnership that will significantly increase the engagement and commitment of the corporate and investment community in disclosure of information on greenhouse gas emissions.

The collaboration will see the web-based Global GHG Register encourage companies to respond to the CDP's request for information on greenhouse gas emissions risk management and reporting practices, and for the CDP to recommend to companies that they register their corporate-wide greenhouse gas emissions inventories in the Global GHG Register. The Global GHG Register and CDP will also work together to explore ways to improve the processes and practices involved in greenhouse gas reporting for the benefit of both contributors and users of such information. CDP issued its third information request on behalf of a large group on investors to the world's 500 largest companies in early February 2005. Over 300 corporations answered the questions for the second CDP information request, issued on 1 November 2003 and which was signed by 95 investors with assets of approximately $10tn. These responses can be downloaded, without charge, from **www.cdproject.net**

BG Group Energy Challenge, 25–26 June 2005

This year, 2005, marks the tenth year that BG Group has sponsored this mystery mountain-based challenge event in the UK, designed exclusively for corporate teams within the energy sector. Since it began in 1996, this annual event has raised over £1.25mn for the overseas project work of humanitarian agency CARE International.

Teams of between five and seven participants must raise at least £5,000 for CARE's work with the poorest communities around the world. Although they know they are required to climb three mountains as well as complete a mystery outdoor activity within 24 hours on the day, details of the exact starting point are kept secret until few weeks before the event. Past locations have ranged from the Outer Hebrides, to the Isle of Mull, Yorkshire, and the Lake District, while the mystery activity has ranged from orienteering, to cycling or canoeing. Participants are supported every step of the way, with a full fitness and training plan, together with tips and advice on fundraising, in the run-up to the event.

CARE International works with impoverished communities in over 60 countries worldwide, including places dependent on revenue from oil and gas production such as Angola, Brazil, Chad and East Timor.

Interested? Find out more by visiting **www.challengeseries.org.uk**, see the advert on page 48, or t: +44 (0)20 7934 9470.

Go on, challenge yourself!

UK

Platts has begun publishing euro- *equivalent price values as a supplement to its existing US-denominated prices for a selection of key crude oil and European and US products.*

The UK government has given its con- *sent for the sale by National Grid Transco (NGT) of four of its eight gas distribution networks, covering the North of England, Wales and the West, South of England and Scotland. It is claimed that the sale will bring the structure of the gas industry more in line with the electricity sector, allowing Ofgem to perform 'comparative regulation' when comparing the performance of different distribution networks in setting price controls.*

The UK government has set a target *of generating 10% of electricity from renewable sources, such as wind farms, by 2010. However, the Renewable Power Association (RPA), the British Wind Energy Association (BWEA) and the Scottish Renewables Forum are reported to have claimed that new business rates set by the government and due to start in April could more than triple the taxes paid by some green power generators and seriously impact growth in the sector. At present the UK sources just 4% of its electricity from renewable sources.*

A survey by Platts Power UK shows *that more than 21 GW of new, large (over 10 MW) renewable power projects are being planned by developers in the UK. If all of the projects go ahead, and some large, nuclear and some coal plant stopped generating, the UK could have more than 14% of its generation mix accounted for by renewable plant by 2010, states the company.*

EUROPE

Fortum plans to build a 170,000 t/y *capacity biodiesel plant at its Porvoo oil refinery in Finland. The facility is to be commissioned in summer 2007.*

Turkish CNG company Avrasya Energji *has signed an agreement with Paget Investment of the UK for the purchase of PAGET® machinery and equipment for compressing and distributing natural gas through a chain of CNG refuelling stations to be built in Turkey's largest cities, including Istanbul and Ankara. Natural gas is fast becoming a*

D1 Oils set new targets

D1 Oils, the UK-based low cost producer of biodiesel, has accelerated its targets for the planting of *Jatropha* in India by its joint venture company D1 Mohan Bio Oils. The new targets are for the planting of 100,000 hectares of *Jatropha* in India in 2005 – a significant increase over the 5,000 hectares estimate used at the time of D1 Oils' admission to the AIM in 2004. Once mature, this initial planting should yield approximately 250,000 to 300,000 t/y of crude *Jatropha* oil. D1 Mohan has also reaffirmed its medium-term objective of planting 5mn hectares of *Jatropha*.

In addition, the operational model has changed such that contract farmers will now purchase seedlings and planting materials from D1 Mohan financed by local banks. At the time of D1 Oils' admission to the AIM, it was assumed these supplies would be provided free of charge. This alteration provides D1 Mohan with additional revenue and enables the business to expand more rapidly as the working capital requirements for each hectare are reduced, says D1 Oils.

Furthermore, D1 Oils now has the option to export 25% of the crude *Jatropha* oil produced by D1 Mohan for sale to international customers. Previously, all crude *Jatropha* oil produced by D1 Mohan was to be retained for domestic biodiesel production.

D1 Oils has also entered into a number of 10-year crude *Jatropha* oil supply agreements with independent suppliers. These supply agreements are in addition to those detailed in its AIM admission document and separate from the targets agreed by D1 Mohan. D1 Oils anticipates that these new contracts will provide an additional 10,000 t/y of crude *Jatropha* oil for export in 2006, rising to 50,000 t/y in 2009.

UK has cheapest pre-tax fuel prices

Survey data of 11 major EU countries shows that the UK continued to have the cheapest pre-tax petrol and diesel pump prices in 2004, despite a background of volatile crude oil and product markets, reports UKPIA (UK Petroleum Industry Association). Data from Wood Mackenzie was based on its Opal service that monitors major brand pump prices across 11 EU member countries. It revealed that the UK average pre-tax pump price of unleaded 95 petrol was 21.6 pence per litre (p/l), 0.6 p/l and 1.1 p/l cheaper than the next lowest countries Germany and France.

The UK was also the cheapest pre-tax for diesel, averaging 22.84 p/l, compared with 23.3 p/l in Germany and 23.9 p/l in Spain.

Chris Hunt, Director General of UKPIA, commented: 'This survey underlines just how competitive fuel retailing continues to be in the UK, pre-tax pump prices having been consistently amongst the lowest in the EU over the last eight years. We also have a good refining and supply infrastructure in the UK and despite testing market conditions, our members have been investing at their refineries to prepare for the move to sulphur-free fuels. Combined with new vehicle technologies, these new fuels will help improve fuel efficiency and deliver further improvements in exhaust emissions.'

Competition in fuel retailing is also reflected in the level of gross margin on each litre of petrol sold – the difference between the selling price of petrol and the open market cost. Wood Mackenzie's Opal figures show that this averaged just over 5 p/l in 2004. The gross margin is not just the profit available to a retailer but also represents the sum available to cover costs such as transporting fuel from a refinery, marketing and promotion, and operating a filling station.

These tough conditions have contributed to the continued closure of filling stations in both urban and rural areas of the UK, whose number has declined from over 18,500 in 1992 to 10,500 in 2003 (Source: *Petroleum Review, UK Retail Marketing Survey 2004*).

prime energy resource in Turkey following the recent completion of the Baku-Tbilisi-Ceyhan (BTC) gas pipeline.

Petronas of Malaysia has signed an *agreement with Switzerland-based Bucher Ag Langenthal, also known as Motorex, to market and distribute its 'Syntium' brand of lubricants in Switzerland and Liechtenstein.*

EASTERN EUROPE

Aral plans to sell its network of 69 *filling stations in the Czech Republic, reports* Stella Zenkovich. *According to the Czech Association of Oil Industry and Trade, CAPPO, there were 2,130 filling stations in the Czech Republic last year, of which some 540 were foreign-owned.*

MIDDLE EAST

The construction of Kuwait National *Petroleum Company's (KNPC) fourth oil refinery, which will have a 450,000 b/d capacity, is to start in early 2007 and is to be completed within three years at a cost of 1bn Kuwaiti dinars, reports* Stella Zenkovich.

RUSSIA/CENTRAL ASIA

Lukoil has notified the European *Commission about its intention to acquire shares of Teboil Ab and Suomen Petrooli, in a bid to sell low-sulphur fuel produced at its Perm refinery to the Finnish market. Teboil Ab and Suomen Petrooli operate 289 service stations and 132 diesel fuel outlets in Finland, and also manufacture and sell lubricants. They are also involved in the refined petroleum products sector.*

JSC Sibneft has signed a four-year *contract with Shell Global Solutions Eastern Europe, which is designed to underpin an overall performance improvement programme thataims to reduce operating costs, boost energy efficiency and improve margins at the Omsk refinery in western Siberia. The refinery currently processes about 14mn t/y of oil (approximately 285,000 b/d).*

Turkmenistan is shortly to commis- *sion on its border the first of a number of service stations to provide cheap petrol, diesel oil and lubricants to the citizens of Uzbekistan. Two more outlets are to be built within*

IPE launches UK electricity baseload index

In response to industry demand for a viable market index on which to base physical deals, the IPE (International Petroleum Exchange) recently announced the launch of its UK Electricity Baseload Index. The first pricing period will be for the March 2005 contract.

'Since the liberalisation of the UK power market in 2001, market participants have sought an appropriate index on which to base large bilateral physical deals. The clear methodology and price transparency of this index, coupled with the IPE's RIE status, and the financial security of a cleared product, delivers a robust solution to the industry,' comments the Exchange. This addition to the suite of IPE indices follows the launch of the IPE NBP Natural Gas Index, now widely referenced as a benchmark for indexed natural gas transactions.

The IPE UK Electricity Index is calculated as a rolling average of the front month settlement price for each trading day, with the final index being that calculated on the expiry day of the front month.

Under the first major deal to be based on this index Accord Energy, the wholesale trading arm of Centrica, and EDF Trading concluded a transaction approaching 1/2-GW of March baseload electricity, demonstrating their commitment to supporting products that will increase liquidity in the UK power market. IPE Member broker, Spectron Energy Services, brought together Accord Energy and EDF Trading as the parties to the trade.

British Energy trading

Shares in British Energy were reported to have dropped on 17 January, after the company's first day back trading on the London Stock Exchange. The UK's largest power firm is trading again after a £1 billion debt-for-equity restructuring – in what Chairman Adrian Montague called 'one of the most complicated restructurings in UK corporate history'.

Shares opened at 286 pence, rose as high as 289 pence, but then fell back to 263 pence as several analysts gave valuations below that level. Morgan Stanley gave an estimate of 210 pence and advised investors to be cautious. 'Due to its very high fixed-cost base, British Energy has significant operational gearing. Financially, the company is highly exposed to both operational improvement and movements in UK power prices,' the bank said in a research note.

Forecourt deal

ChevronTexaco and Somerfield, the fifth largest food retailer in the UK, have signed a memorandum of understanding (MoU) on an exclusive basis, to negotiate the sale of approximately 140 Texaco-owned service stations in the UK to Somerfield.

The proposed agreement is part of ChevronTexaco's strategic direction to improve returns by focusing on areas of strength and enhancing and managing three world class brands – Chevron, Texaco and Caltex.

Under the proposed agreement, Texaco would continue to supply the approximately 140 Somerfield-owned service stations with fuel and the forecourts would still be branded Texaco. The convenience stores would operate under the Somerfield brand.

Pilot PEM fuel cell system starts up

NedStack Fuel Cell Technology and Akzo Nobel Base Chemicals have reported the successful start-up and operation of a proton exchange membrane (PEM) fuel cell system in Akzo Nobel's chlorine electrolysis pilot plant in Rotterdam as the first step in the development of a 50-MW fuel cell power plant.

The Akzo Nobel chlorine pilot plant is producing chlorine through a membrane electrolysis process. This process generates chlorine and caustic soda lye as main products, and hydrogen. NedStack has installed PEM fuel cells that consume hydrogen produced in the plant, and convert this hydrogen to electric power. This fuel cell generated power is used in the same pilot plant for electrolysis process.

NedStack has also started the production of a second fuel cell power module, rated at 200 kWe peak power and which will be installed in the Akzo Nobel production plant in Rotterdam, scheduled for mid-2005. A fuel cell power plant will use the hydrogen that is produced in a large chlorine electrolysis plant. This plant will use the power generated by the fuel cells. In this way a substantial reduction of the net energy consumption can be accomplished, says the company. Preliminary specifications for the fuel cell power plant are: 50 MW nominal power, 200 MW rated fuel cell peak power, 60% electric efficiency, zero emission, and 40,000 hours fuel cell operating time without maintenance.

the next few months, reports Stella Zenkovich.

Azpetrol of Azerbaijan and the gov- *ernment of Moldova have signed a contract under which Azpetrol is to construct an oil port, open 50 service stations and build an oil refinery in Moldova, writes* Stella Zenkovich.

ASIA-PACIFIC

PetroChina is reportedly planning to *spend $3.3bn to more than double the refining capacity at Dushanzi Petrochemical in the north-western province of Xinjiang in order to meet rising demand for fuels and raw materials to make plastics. It is planned to increase capacity to 10mn t/y by 2008. China's consumption of petrochemicals is growing by 8–10%/y.*

The US energy company El Paso *Corporation is reported to have decided to sell its Asian power assets in a bid to raise an estimated $500mn to help pay mounting debts. El Paso runs power plants with a capacity of 4,153 MW in Bangladesh, Pakistan, India, China, Indonesia, South Korea and the Philippines.*

LATIN AMERICA

Venezuelan President Hugo Chavez is *reported to have announced plans to sell eight Citgo-owned refineries in the US in a bid to reduce Venezuela's dependence on the country. State-owned Citgo accounts for nearly 15% of US refining capacity.*

Ecuador is seeking participation for *setting up a new 200,000 b/d refinery with an investment of $2.5bn. The country currently has three refineries in operation, with a combined capacity of 176,000 b/d. According to Minister for Energy and Mines Eduardo Lopez Robayo, India's Oil and Natural Gas Corporation (ONGC) has shown an interest in the project.*

WORLD

The International Civil Aviation *Organisation (ICAO) has claimed that navigation technology allowing planes to fly closer together – called reduced vertical separation minimum (RVSM) systems – will improve fuel costs by 0.5–1%, based on a cost-benefit analysis of north Pacific routes, reports* Keith Nuthall.

Low-sulphur bunker fuel contracts

Wallenius Wilhelmsen, the Swedish shipping and logistics company, has signed two key contracts for the supply of low sulphur bunker fuel – with a sulphur content of just 1% – that will help the company meet its ambitious environmental targets for 2005.

A three-year contract has been secured with Shell Marine Products to purchase 200,000 to 300,000 t/y of low sulphur bunker fuel until 31 December 2007. The fuel will be supplied in Gothenburg and Bremerhaven. The second contract has been signed with ExxonMobil for the supply of 100,000 to 115,000 tonnes until 31 December 2005. The fuel will be provided in Southampton.

Last July a contract was signed with Petrobras for supplying about 150,000 tonnes of bunker fuel in Singapore with a sulphur content of 1.5%. The contract runs until 30 June 2005.

At the end 2004 Wallenius Wilhelmsen met its overall target of only using fuel with a maximum sulphur content of 1.5%. The company's 2005 end-of-year goal is to ensure that its entire fleet of 60-plus vessels keeps to this strict low sulphur fuel target – well ahead of current legislation.

International standards will require that by the middle of 2006 ships will need to meet a 1.5% sulphur standard in the Baltic. Legislation will also require that in 2007 a similar figure needs to be reached for the North Sea, Irish Sea and the English Channel, while the remainder of the world will need to adhere to a 4.5% target.

Purchasing bunker fuels with low sulphur content is just one of several measures that Wallenius Wilhelmsen is undertaking to reduce its impact on the environment. The company's owners are already altering main engine fuel combustion to minimise emissions, implementing the use of tin-free antifoulant bottom paints on hulls, employing innovative methods of treating ballast water, using double hulled vessels, changing cooling agents used in refrigeration plants, using biodegradable oil in the stern tubes, finding more environmentally friendly systems to put out fires, and using bilge water treatments achieving an oil content of 5 ppm.

In addition, in June 2004, Wallenius Wilhelmsen became the first non-container shipping company to join The Clean Cargo Group – a global consortium of multinational manufacturers, shippers and carriers, to promote cleaner and more environmentally sustainable transportation. In September 2004, the company signed a three-year agreement with WWF-International to help support the work of WWF's global marine programme on preserving and promoting high seas conservation, ie areas outside the exclusive economic zones of national states.

ExxonMobil launches new lubricants in US

ExxonMobil has introduced to the US market a line of high-endurance motor oils designed for longer oil change intervals, as recommended by many of today's vehicle manufacturers. The new motor oils are claimed to deliver proven performance and guaranteed, long-lasting protection of critical engine parts for 5,000, 7,500, or 15,000 miles.

The new line consists of:

- Mobil Clean 5000 and Mobil Clean High Mileage – two new conventional oils formulated with 16% more cleaning agents than Mobil conventional oil for exceptional cleaning performance and guaranteed protection for 5,000 miles.
- Mobil Clean 7500 – a new synthetic blend formulation with 18% more cleaning agents than Mobil Clean 5000 to guarantee long-lasting protection for 7,500 miles.
- Mobil™ Extended Performance – a new fully-synthetic formulation containing the Advanced SuperSyn System which includes 50% more SuperSyn, ExxonMobil's proprietary high-performance synthetic component, and boosted levels of special cleaning agents to guarantee engine protection for 15,000 miles.

Centrica's first coal-indexed power deal

Centrica has agreed its first coal-indexed power purchase agreement, which will see International Power supplying a daily 250 MW volume of peak electricity to British Gas, commencing in October 2005. The agreement, which will run for three years, is in line with Centrica's aim of bringing greater diversity to its power portfolio by including coal indexation. The price paid under the contract, which will deliver around 2.34 TWh over the term, will be directly indexed to international coal prices.

Photo: B Meep

Talking up the reservoir

Following its well-documented financial woes over the last few years, the geophysical services industry is now in a healthier condition – focused mainly on persuading the oil and gas industry to follow its lead in developing technology to optimise the value in today's reservoirs as well as those yet to be discovered. Andrew McBarnet,* *tells the unfinished story of the industry's change in fortunes, the outcome of which is unpredictable.*

Suppliers of geophysical services to E&P companies around the world got themselves into a terrible mess at the end of the 1990s, from which they are only now recovering. It wasn't all their fault. The cyclical downturn of the day was exacerbated by unprecedented consolidation of the customer base, particularly among the majors, followed by a hiatus in exploration spending. This was more than enough to expose rampant over-capacity in the seismic sector, especially in the capital-intensive marine seismic fleets. Subsequently, ill-advised investments in increasingly speculative, but costly, multi-client 3D seismic surveys to keep vessels active nearly capsized the whole business.

The fall-out saw Schlumberger in 2000 merge its Geco-Prakla subsidiary with Baker Hughes' Western Geophysical in a 70:30 joint venture to create easily the biggest company in the industry. Within a year of its establishment, WesternGeco was forced into a radical restructuring in which vessels and staff were sidelined. Petroleum Geo-Services (PGS) – star of the 1990s with its highly productive, revolutionary design Ramform vessel operations – responded to the crisis by investing in production services, notably the FPSO market, and by attempting to merge with competitor Veritas DGC. The fit looked good on paper, but Veritas – vulnerable but not desperate – baulked at the massive \$2.8bn of debt being carried by PGS. There followed a touch and go period for PGS before rescue and refinancing led by Norwegian Jens Ulltveit-Moe.

The other main seismic contractor – Compagnie Générale de Géophysique (CGG) – went through a number of contortions to stay afloat, including merger talks with its rivals. The rock on which it was able to rely during the difficult times was its land seismic acquisition equipment manufacturing subsidiary, Sercel, which even now continues to outperform the market.

Healthier climate

The good news is that geophysical service providers look in much better shape today. It took a long time but the main players, by and large, heeded their own calls to reduce capacity on the marine side. True, Dalton Boutte, CEO of WesternGeco, has been heard to complain that as fast as his company takes vessels out of service, they seem to reappear elsewhere. But Thierry Pilenko, who last year took over at Veritas from long-time CEO Dave Robson, observed recently that larger, high-tech 3D seismic vessels were being booked months in advance. That hasn't happened in a long time. The explanation may lie simply in the 15–20% increase in oil company E&P expenditure predicted by analysts for 2005; but it also suggests contractors have finally got supply better in synch with demand so they are able to improve upon previously unsustainable margins.

The healthier climate for doing business is a plus. Rather disarmingly, however, the precise direction of the market is less than clear. This is partly a case of the geophysical services industry being victim of its own technology-driven ingenuity. For some time now, all the talk has been about the reservoir. Oil companies, it is supposed, will find most 'new' oil from already known reservoirs, many already in production, thanks to advances in technology. Integration of geoscience and petroleum engineering expertise is expected to make a significant contribution to this process of maximising production from existing, and for that matter, future oil and gas developments.

Reservoir focus

This has been the mantra behind a wave of new reservoir-oriented technology, in which arguably the geoscience community has got ahead of itself. Not for the first time, it finds itself playing the uncomfortable role of market maker for new technology which oil and gas companies may or may not buy into. This dilemma is partly the result of the burden of R&D passing from oil companies to the services sector, a development frequently deplored by seismic industry leaders. They argue that their investments in new technology never get the price premium they deserve from obsessively cost-conscious oil companies. A more subtle problem is that that the oil company model of having its E&P projects managed by asset teams fosters risk averse decision-making which militates against new ideas and methods.

Whatever the reasons, the services sector would like to be further along the road than it is with oil company uptake of seismic acquisition technologies such as 4D, multi-component and life of field seismic, as well as some of the very fancy compute-intensive processing, interpretation and visualisation methods aimed at maximising the information value of available data.


Photo: Veritas DGC

Land seismic

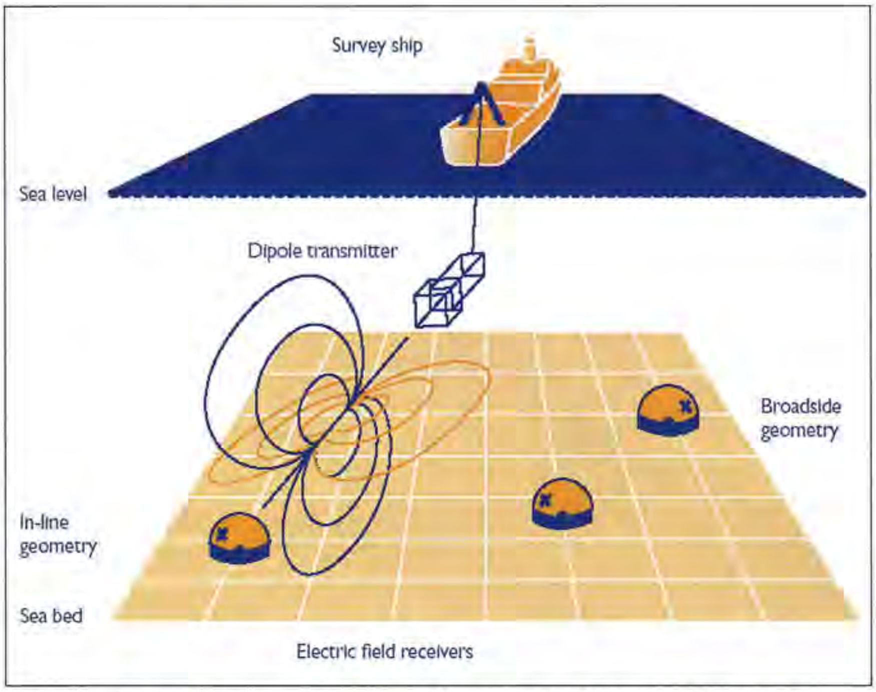
Bob Peebler, CEO of Input/Output (I/O), last October at the annual meeting of the Society of Exploration Geophysicists in Denver spoke for many companies when he complained about the 'snail's space at which oil companies are embracing the new technologies, even when the financial results can be outstanding'. Peebler, who built Landmark Graphics into a 'must have' buy for Halliburton in the 1990s, also has his own agenda. He is re-positioning I/O away from its traditional seismic acquisition equipment manufacturing role to take advantage of what he calls 'the third seismic wave'. First there was 2D seismic, then 3D seismic, and now the 'digital full wave' based on technologies to deliver subsurface images that enable higher resolution, differentiate rock types, and distinguish fluid types and movements.

In pursuit of his vision, Peebler has so far acquired Concept Systems, the dominant provider of navigation and positioning software services for seismic surveys, and GX Technology, supplier of advanced image processing of seismic data. But to judge from I/O's results to date with its VectorSeis digital acquisition systems for land and marine, oil companies are indeed being slow to adopt the 'third seismic wave'. There has been one significant sale of the land system in the US, one in Poland and two in China.

4D seismic

In fact, the seismic industry has been most successful in selling 4D seismic which, with well over 70 surveys carried out worldwide, is well beyond proof of concept stage if not mainstream. Initially oil companies, even if they understood the science, regarded 4D seismic ('time-lapse' 3D surveys) as an expensive luxury. This was partly fuelled by the assumption that the best results could only be acquired with multi-vessel ocean bottom cable (OBC) operations. OBC enables the acquisition of multi-component seismic data in which conventional hydrophones for marine seismic can be combined with geophones (which only work on land or on the seabed) to collect both 'p' (hydrophone) and 's' (geophone) wave data.

To make 4D affordable, seismic companies have shown that 3D seismic surveys can be successfully repeated using conventional towed streamers, thanks to new developments in high resolution data acquisition and increasingly sophisticated survey planning and positioning. The unexpected outcome is that most 4D seismic is being acquired with streamers, a trend which shows no sign of tailing off.



How UK company Offshore Hydrocarbons Mapping (OHM) deploys controlled source electro-magnetic (CSEM) sounding to detect hydrocarbons

WesternGeco maintains that its Q-Marine technology is uniquely suitable for 4D seismic survey work because high resolution data is assured by the unprecedented recording of each individual sensor in the receiver system (as opposed to groups of sensors), and the use of steerable streamers for accurate positioning. For Statoil, the company has now carried out over the Norne field, offshore Norway, three Q surveys over the same target, reportedly imaging significant changes in the reservoir sufficient to cause a rethink of some aspects of the reservoir management strategy. WesternGeco has equipped five of its vessels with Q-Marine and earlier this year Schlumberger CEO Andrew Gould claimed the technology was gaining traction (Q was dogged early on by a 'too expensive' tag). The main competitor to date in the 4D seismic stakes has been PGS, which has successfully persuaded a number of oil companies that its high density (HD3D) towed streamer acquisition system can achieve comparable results at lower cost than Q.

It is taking longer for oil companies to get their heads around the idea of spending money on acquiring multi-component data using OBC or some other seabed method. The concern is not just cost, but doubt about the added value of the data. As a result oil companies have been adopting a potentially unhelpful 'wait-and-see' policy. The apparent impasse has provided the opportunity for three small Norwegian companies to exploit the gap in the market. Multiwave Geophysical, Reservoir Exploration Technology (rxt) and Seabed Geophysical have all found different methods to acquire multi-component data at a price that the oil companies will pay. In rxt's case, the company is deploying in the Gulf of Mexico the first application of I/O's VectorSeis Ocean technology; while Seabed Geophysical, in an inaugural survey for Pemex, used a proprietary node – rather than cable-based-system designed particularly for deep water and for work around obstructed areas of the reservoir target area.

Technology of choice

In geoscience circles there is a clear assumption that permanent OBC systems will eventually be the 4D seismic technology of choice, resolving resolution and repeatability issues and allowing the recording of 3D seismic on demand to monitor reservoir performance. It is spoken of as an integral part of the automated E-field of the future. So far, only BP on the Valhall field, offshore Norway, has actually put this life of field (LoFS) concept into any sort of practice. Shell is the only company to have followed suit on its Mars field in the Gulf of Mexico, where Multiwave Geophysical is a key contractor using the same Oyez Geospace seabed cable deployed on Valhall.

BP's LoFS team has spoken enthusiastically about the Valhall project. It is based on a network of buried seabed receiver cables connected to the platform, so that data from each survey by a shooting vessel can be immediately uploaded by fibre optic link from the platform to an onshore processing centre. There have been at least four surveys over the reservoir with reportedly satisfactory results. However, there has been no word on extending the experiment to suitable locations in the Gulf of Mexico and the Caspian, which was the original scenario. The buzz is that processing issues to do with multi-component data and turnaround times of final results have caused some anxiety. Gossip aside, few other oil companies are showing any signs of diving in with their own permanent OBC systems.

CSEM sounding

One offshore technology that has taken hold over the last couple of years is the use of controlled source electro-magnetic (CSEM) sounding to detect hydrocarbons, in which ExxonMobil has been a major promoter. Norwegian company Electro-Magnetic Geophysical Services (emgs), a spin-out from Statoil, claims to have been the first to spot the potential application of seabed logging, or CSEM, for the direct detection of the presence of hydrocarbons, particularly in deep water. Two other companies – UK-based Offshore Hydrocarbons Mapping (OHM) and AOA Geophysical Services (recently acquired by Schlumberger) – offer similar services designed to be used in conjunction with seismic survey data to provide confirmation of hydrocarbons before drilling decisions.

This could be particularly valuable in locations such as the deep water of West Africa or the Gulf of Mexico, where each well can cost $60mn and upwards. The system is based on towing a horizontal electrical dipole close to the seabed emitting an ultra-low frequency EM signal which is recorded by stationary seabed receivers. The high resistivity of hydrocarbon filled reservoir rocks compared with reservoirs filled with saline formation water makes EM sounding a suitable tool for detection of subsurface hydrocarbons.

Late last year an Edinburgh University spin-off company including Professor Anton Ziolkowski and Dr Bruce Hobbs was launched, offering a variation of the technique said to be applicable to land operations and with instant results not possible with marine-based CSEM methods. The company – Multi-transient Electromagnetic (MTEM) – says that its method is best applied with knowledge of the seismic data mainly for location of likely prospect areas.

On land battle

On land the seismic acquisition story is very different. On the technology front, there is a head-to-head battle between market leader Sercel and I/O to supply contractors with high resolution seismic recording equipment. But the traditional US and European contractors such as WesternGeco, CGG and Veritas – as well as others like PGS and Grant Geophysical, which operates internationally – are now facing serious competition from previously unconsidered quarters.

The biggest threat comes from the Chinese company BGP, but a number of Eastern European, Indian and Russian enterprises all offer technically proficient services – in many cases equipped with exactly the same Sercel or I/O technology. Their winning pitch is based upon lower cost, which has proved popular particularly where national government agencies in less developed countries are the customers.

There is a sense of resignation about how land seismic operations are evolving into a commodity. This is certainly one reason why western geophysical companies are focusing increasingly on high tech, high value operations such as pre-stack depth migration and other sophisticated processing techniques to extract the most out of seismic data, whether land or marine. There is now a whole niche market being developed by companies such as Rock Solid Images, Ødegaard, Hampson Russell and Fugro-Jason to extract rock properties from seismic data through well log analysis, seismic inversion and time-lapse prediction which make more sense to the petroleum engineer and holds out the possibility of a more integrated approach to reservoir characterisation in hydrocarbon exploration and production. Visualisation centres, usually primed by Silicon Graphics supercomputing power, are now a commonplace for oil companies and contractors, facilitating better understanding of data at every stage of processing and interpretation, and encouraging multi-disciplinary collaboration.

Big names in the seismic software solutions business such as Schlumberger Information Systems, Landmark Graphics and Paradigm, as well as the smaller niche companies, all run the already mentioned risk of getting ahead of the market – by being too complex! A familiar refrain these days is that there just aren't enough geoscientists left in the oil companies with the knowledge and experience to understand and judge the highly sophisticated products being brought to market. Given the ageing profile of the geoscience community as a whole, this situation is likely to get worse rather than better unless there is a radical rethink on the recruiting front.

Photo: Fugro Airborne Services

Fugro Airborne Services' GeoRanger – an unmanned airborne vehicle (UAV) developed for oil exploration aero-magnetic survey work in remote and inaccessible locations

Preparations for the so-called 'crew change' ahead need not detain us here. Right now the geophysical services industry is in better heart than it has been for over half a decade, and its ceaseless drive to improve the technology available for cost effective E&P continues unabated.

The defence rests its case with the latest service provided by Fugro Airborne Services. For oil exploration aero-magnetic survey work in remote and inaccessible locations, the company can now deploy an unmanned airborne vehicle (UAV), weighing 40 lbs fully fuelled. After catapult launching, GeoRanger will fly along a predetermined survey line route for up to 15 hours gathering data before returning to its starting point. Safe landing requires nothing more than a dangling piece of bungy cord suspended from a boom with a GPS homing device on the top. That's got to be progress! ●

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North Africa steps on the gas

With the expansion of world gas trade largely driven by the impending US gas crunch and declining capital costs of LNG, and rising west European gas demand projected to grow at an average annual rate of 2% in 2001–2025 to 151tn cf, foreign investment is rapidly expanding in North Africa's major oil and gas producers – Algeria, Libya and Egypt.* Mojgan Djamarani *reports.*

Europe, which is North Africa's natural market, currently imports some 307bn cm/y of gas via pipeline, around 12% of which is supplied by Algeria. A further 8.8% of Europe's gas import needs are met by LNG from Algeria and Libya.

LNG currently accounts for an equally small share of overall US gas imports – 12.7%. However, its share of the gas trade is set to grow following recent technical advances in the design of LNG facilities that allow for a better match between potential supply and market demand. Cedigaz estimates that LNG trade could reach about 295bn cm/y by 2010 and 430bn cm/y by 2020, or about 32% of world gas trade (compared with 168bn cm/y in 2003). However, given the long lead times required to bring LNG facilities on line, it is unlikely that the current high gas prices fuelled by gas shortages in the US will be affected by LNG trade.

In Europe, LNG competes with pipeline imports. In some countries such as Spain and France, LNG's share of gas imports is quite high – 63% and 24% respectively in 2003. In the years to come this gas-to-gas competition will intensify and the North African/southern Mediterranean littoral producers are positioning themselves to supply these markets by adding capacity to both their pipeline connections to Europe as well as LNG facilities. From the perspective of the international oil and gas companies, these facilities fit well within their European and Atlantic supply chains. In 2003, Algeria and Libya accounted for almost 16% of total world trade in LNG and 7.3% of gas pipeline trade as only Algeria had the capacity to export by pipeline.

Algeria

Algeria has been leading the way now for some time. It is Europe's second largest source of imports after Russia and enjoys an extensive distribution network into Europe. Algeria expects to increase gas exports to more than 3tn cf/d by 2010 as new upstream projects come onstream. Last year, the $2.5bn In Salah project – led by a consortium of Sonatrach 50%, Statoil 31.85% and BP 18.5% – commenced gas sales which are expected to peak at 315bn cf/d and will boost Algeria's gas exports by 15%. The consortium's other gas project, the 900mn cf/d In Amenas development, is expected to come onstream in 2006.

A major contributor to future increases in Algeria's gas export capacity is the Gassi Touil integrated development project, which was awarded to a joint venture of Repsol YPF 60% and Gas Natural SDG 40% last November. It involves exploration, development and marketing of LNG from the Gassi Touil zone in eastern Algeria. The Spanish joint venture will invest $1.6bn over a 30-year period. A LNG facility is to be built at Arzew, with an annual capacity of 5.2bn cm – equivalent to 20% of Spain's domestic consumption – and planned start-up in 2009. In 2003 Algerian LNG met 31.5% of Spain's and 22.7% of France's gas imports.

State-owned Sonatrach is also increasing its pipeline export capacity. It plans to increase the capacity of its MEG pipeline into southern Europe to 11.5bn cm/y by 2006, up from the current 8bn cm/y, while raising the capacity of the TransMed pipeline to 32bn cm/y, up from the current 24bn cm/y. In addition, work is also scheduled to start in July on the first of two new pipelines – the new $1.5bn, 450-km Medgaz pipeline that will carry between 8bn and 16bn cm/y of gas under the Mediterranean Sea to Spain. It will be built by the Medgaz consortium in which Sonatrach and Cepsa each have 20% stake, with the remainder divided equally between BP, Gaz de France, Total and two Spanish utilities.

The other pipeline is the 1,470-km Gasli line, which is expected to carry 10bn cm/y of gas from eastern Algeria under the Mediterranean to Cagliari in Sardinia. It will be build by a consortium

Photo: www.eni.it

Castoro 6 **pipelaying Transmed pipeline**

comprising Sonatrach 40%, Edison 20%, Wintershall 15%, Enelpower (Italy) 15% and EOS Energia (Italy) 10% at an estimated cost of $2bn. The pipeline could be online by 2008.

Sonatrach has also put out a tender to build a 4mn t/y new LNG train at Skikda export terminal to replace the three trains that were destroyed in an explosion at the terminal early last year.

Libya

Expansion of natural gas production is also high on Libya's list of priorities. It has large reserves of natural gas that it wants both to export to Europe and to use at home instead of oil in power generation in order to free up more oil for exports. Although the country is

Nigerian competition for North African producers

The more abundant and more widely spread reserves of gas worldwide compared to oil means that the North African producers face competition for foreign investment and buyers not just from each other but also from the Middle East and Nigeria. By the same token, the oil majors are in a better position to avoid making the large-scale investments that gas projects require in political hotspots. In this regard Libya is in a better position than Algeria, while Egypt is in an even better position as it is free from the political violence and civil unrest that grips Libya, Algeria and Nigeria. In Algeria, the international energy companies reportedly spend as much as 9% of their budgets on security.

Although the Middle Eastern producers have been attracting most of the attention from foreign investors, especially Qatar, their exports are primarily directed at the Asia-Pacific markets. It is from Nigeria that the North African producers will meet their toughest competition.

In Nigeria, there is currently no dedicated exploration for gas, with the country still flaring about 40% of the 19.2bn cm (2003) of gas it produces. It is the stated aim of the Nigerian government to end gas flaring by 2008. To show its determination in achieving this goal, the government is including for the first time in its next oil licensing round (to be held in 1Q2005) a condition of contract gas utilisation within a set time frame and is threatening revocation of oil mining licences.

Nigeria is trying to expand the market for its gas resources both regionally and internationally. In 2003, it exported 11.9bn cm of LNG. It is enlarging its 397bn cf/y LNG facility on Bonny Island (NLNG) by adding two more trains at a cost of $2.1bn to the existing three trains. These are expected to start operation by June of this year. Shell Nigeria is expected to supply 11.35bn cf/y for the first five trains.

Plans have also been approved for a sixth train by 2007 that would bring the total capacity of the NLNG facility to 1.1tn cf/y. Half of the feed gas will come from associated gas, including that from offshore fields. NLNG will supply customers in North America and Europe. Total has a 20-year agreement, while Shell is to take 53.6bn cf/y from the fourth and fifth trains and 146bn cf/y from the sixth train to supply North America and Europe. BG has also signed a 22-year agreement to supply its Lake Charles re-gasification facility in Louisiana beginning in 2005/2006 (part of which will come from Nigeria as well as from other sources).

A second LNG facility – the Brass River LNG plant in Bayelsa state – is also to be built by a consortium of ConocoPhillips, ChevronTexaco and Agip for an estimated $3bn. It will consist of two trains with a capacity of 974bn cf/y and is to become operational in 2009.

In another move, the NNPC-ChevronTexaco joint venture Escravos gas project – which currently supplies domestic demand – is to switch over to exports. The 400mn cf/d of gas from ChevronTexaco's northern offshore oil fields that is processed at the plant is to serve as feedstock for a $1.3bn GTL facility which is due onstream this year. The new facility will produce 176.5mn cf/d of LNG.

According to NNPC, Nigeria is set to earn $6bn/y from LNG sales as of 2007, and by 2008 the projected income from LNG is expected to rival that from oil.

The $600mn West African Gas Pipeline (WAGP) project is designed to provide Nigeria with a regional outlet for its gas. The 681-km pipeline will extend both onshore and offshore from the existing Escravos-Lagos pipeline at Alagbado to a final planned terminus in Ghana. It will initially transport 120mn cf/d to Ghana (84%), Benin (7%) and Togo (9%) beginning in June 2005. Gas deliveries are expected to increase to 150mn cf/d by 2007, 210mn cf/ in seven years and be at 450mn cf/d when the pipeline is functioning at full capacity.

Nigeria is to fund 49% of the total $600mn project cost, with its foreign partners funding 51%. The World Bank, whose backing of the project was deemed crucial by ChevronTexaco, has contributed $125mn in guarantees in support of the pipeline.

The World Bank's support for the project, however, has not mitigated opposition to the WAGP. Civil society groups in the recipient countries have voiced concerns about the violence and instability of the oil and gas communities in Nigeria's Niger Delta region where the feed gas is to come from and the risk of exacerbating crises over resource ownership. Another controversial point has been the fact that ChevronTexaco and Shell, rather than the participating countries, own more than half of the company that will build, own and operate the pipeline. Meanwhile, environmental groups have raised concerns over insufficient environmental impact assessments of the project and estimate that some 50,000 families in Nigeria, Ghana, Benin and Togo could be displaced as a result of the project. ●

awash with high quality cheap oil – costing less than a $1/b to produce – because most of Libya's oil fields have been developed with old US equipment for which it could not acquire spare parts while the US embargo was in place since 1986, oil production has stagnated and reserves replacement declined. However, with the lifting of US sanctions last year and expected changes to its hydrocarbon legislation, Libya could outdo its North African neighbours in attracting foreign investment in the future.

Completion of the West Libyan Gas Pipeline (WLGP) last year is set to turn Libya into a key participant in the Mediterranean Sea economic community. Coupled with the Egypt-Jordan pipeline, which was commissioned in 2003, it could become a major artery for future gas exports from North Africa and the western Middle East to Europe. The $6.6bn WLGP project is a 50:50 joint venture between Eni/Agip and Libya's NOC. It is expected to operate at full capacity in 2006 when gas production from the Wafa field on the Algerian border and Bahr Essalam field, 100 km offshore in the Gulf of Gabes, reach peak levels. A processing plant at Mellitah on the Libyan coast will process 10bn cm/y of gas, of which 2bn cm/y will be destined for the domestic market. The rest will be exported via the 516-km subsea Green Stream pipeline to Gela in southern Sicily, and from there onto southern Europe. Buyers of the gas are Italy's Edison Gas and Energia Gas, and Gaz de France.

The WLGP will also facilitate the development of smaller discoveries in south-western Libya along the route of the two onshore pipelines from the Wafa field to Mellitah. It will also encourage further exploration of Libya's narrow continental shelf in the Gulf of Gabes, using the Sabratha offshore production platform that is due to become operational by this summer.

With the lifting of US sanctions, Libya's LNG plant at Masra el Brega can also now be revamped using American equipment. The Esso-built plant currently operates at a third of its designed 100bn cf/y capacity. Shell is currently negotiating proposals with the Libyans, but wants firm assurances of the amount of feedstock gas that will be made available to it before concluding any agreements. The company reportedly is anxious to get a foothold in the North African LNG market in order to maintain its gas strength in Europe.

Egypt

Egypt's star is also rising as two LNG export terminals come online this year. Its natural gas sector is expanding rapidly, with production having more than doubled in 1999–2003 and expected to increase to 5bn cf/d by 2007. As oil exports decline, finding ways to export gas are becoming more important to Egypt's balance of payments. There is talk of extending its gas pipeline to Aqaba, in Jordan, to Syria and Lebanon. Shell has tabled proposals for building a 75,000 b/d GTL (gas-to-liquids) plant using reserves from its NEMED find as feedstock. However, the favourite option is LNG.

Photo: www.anadarko.com

Drilling in Algeria

The first of Egypt's two LNG projects, SEGAS, was commissioned at the beginning of the year. Located at Damietta, on Egypt's north coast on the Mediterranean, the $1.4bn facility was built by Spain's Union Fenosa, in which Eni has a 50% stake. The 4.8mn t/y facility is not tied in with any gas fields, but instead will be supplied with gas from EGAS' distribution network. It is a joint venture of Union Fenosa 80%, EPGC 10% and EGAS 10%. The project will reach full commercial operations in March and will have a throughput capacity of 6bn cm in year one and 7bn cm in year two. Union Fenosa will initially be the sole off taker, but once full capacity is reached it will take 4bn cm/y – 3bn cm for Spain and 1bn cm for the US market. BG Group has a five-year contract to export 700,000 t/y from the plant to its North American markets, beginning in 1Q2005.

Egypt's second LNG project, ELNG, is being built by a consortium of BG, Petronas, Gaz de France and EGPC at Idku. It is tied into gas reserves from Burullus Gas' Simian-Sienna and Sapphire offshore fields. ELNG's first train is expected to start operations this year and the second train next year. Gaz de France will be the off taker of the first train under a 20-year agreement for 3mn t/y. BG Group will take production from the second train, which will initially be delivered to its Lake Charles, Louisiana import terminal for the US market. This will be switched over to the Brindisi import terminal in Italy once its construction is completed. BG will then supply the US market from its operations in Trinidad.

ELNG is already sizing up interest from other oil companies for supply and offtake agreements for a third train. At the same time, the BG-led consortium Burullus Gas is stepping up its exploration programme to find new reserves to feed the third train. Currently, gas from BG's producing fields – Scarab and Saffron in the West Delta Deep Marine concession and 300mn cf/d Rosetta field – goes to the domestic market. The company was recently awarded two new concessions, el Manzala and el Burg, east of the Nile Delta.

Recent gas discoveries on Apache's Kalda concession in the Western Desert also offer great potential for increasing Egypt's future gas export capacity. Apache now estimates ultimate recoverable reserves on its concession to be 2tn cf of gas and 40–50mn barrels of condensate. The company has a 25-year, 300mn cf/d gas sales agreement with EPGC, which might be redefined in lieu of the recent discoveries. Eni also plans to bring its 2tn cf of reserves in the Ras El Barr lease and the 7.6bn cm North Bardawil field onstream by 1Q2008, while its 8.7mn boe North Sinai field is expected to come onstream next year. The company expects to spend 10% of its exploration budget for 2004–2007 in Egypt.

Looking ahead

With hundreds of billions of dollars of investment at stake, it is likely that the African gas producing countries will do all they can to encourage interest from the major players in LNG and gas supply business.

This is likely to mean that Nigeria and Egypt will attract more investment than Algeria and Libya, where nationalistic sentiments may inhibit their governments in offering terms that are deemed too favourable to foreign countries.

**Energy Information Administration,* International Energy Outlook (IEO), 2004

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This **4-day** course provides an overview of the economic and contractual aspects of the natural gas industry. The peculiar features of natural gas will be highlighted in order to explain the economic differences between a crude oil chain and a natural gas chain. Gas chains can become very complex, rigid networks which penetrate deep into energy markets and the associated, broad range of crucial economic, marketing and legal issues of the gas industry will be examined.

Who should attend?

This course is particularly appropriate for those with experience in the oil, gas and energy industries wishing to widen their understanding and knowledge of the natural gas business. It is also suitable for those who are concerned with natural gas and work in other sectors such as banking or government where they need an understanding of the industry.

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argus media

Interesting and turbulent times

Sir John Collins FEI, President-Elect of the Energy Institute (right), addressing the annual IP Week Dinner at the Grosvenor House Hotel, London, provided an overview of some of the trends and issues affecting the international oil and gas industry and highlighted the value of some of the Energy Institute's activities. He said...

As it should do, the programme of conferences and seminars during International Petroleum (IP) Week reflects the events and trends of the past year and the challenges facing the petroleum industry in 2005. These are principally security of supply at affordable prices and tackling global warming. The reputation of the industry depends on how successfully it delivers on these challenges.

Upstream, it is the high price of crude oil and its sustainability, the speed and ability of the industry to expand production whilst balancing the environmental challenges, the continuing discovery and development of resources in deep water, the increasing dependence on Russian oil and gas supplies, political instability in the Middle East and operating issues such as oil reserves measurements which have been dominating the headlines. In addition, there are policy uncertainties created by the Gazprom/Rosneft merger and the effective dismantling of Yukos. As if these were not challenging enough, there is the ongoing debate on oil depletion and the ability of new exploration and development technologies to generate the required new production flows. Once again, windfall taxes may creep into the government's agenda.

The downstream industry faces both challenges and opportunities in meeting the current pattern in demand at high crude prices. In doing so, consumers and governments' sensitivity to pump prices will require effective communication and transparency. The refiners benefitted from erratically high but often short-lived profits, whereas the distribution sector faced the challenge of maintaining margins. Additionally, the growth in global demand, especially from Asia, has generated speculation about a worldwide shortage of upgrading and sulphur-removal capacity. The US and Asian refiners are investing heavily in upgrading their units and their prospects appear very good. However, the refining industry in Europe is experiencing product imbalances which must be addressed through a combination of investment and trading.

The world's insatiable demand for natural gas, the cleanest hydrocarbon known to man, adds great weight to the importance of Russia as a supplier, to infrastructure across Europe and in parallel to further development of LNG. In this context, we must not neglect opportunities for extending the life of oil and gas production in the North Sea.

Governments, led by the UK, are designing energy plans to address global warming. It is essential that the industry collaborates in both the design and delivery of such plans. In the UK, a fair start has been made on the supply side with industry responding positively on renewables, for example [see p25]. Delivering energy efficiency targets will, I believe, be more challenging and emissions trading must succeed. The absence of the mighty United States from the playing field is clearly of great concern and our Guest of Honour will hopefully comment on this key issue [see p22].

Role of the EI

In these interesting, if not sometimes turbulent times, the work of the Energy Institute (EI) becomes increasingly valuable to us all. No more so than the

Right and far right: This year, guests were entertained at their tables by magicians, silhouettists and cartoonists (not pictured)

Below: Guests making their way down the Great Room staircase

Technical Programme, which focuses on the publication of test methods, codes and industry best practice. An independent assessment on the period 2001–2002 has demonstrated that the programme offers a very high level of return on investment from industry. Greater awareness of the considerable value offered by this technical activity has been reflected in the increased size and participation from companies in the 2005 programme.

It is enhanced through partnerships with other organisations at global, national and local level. For instance, EI research on aviation fuel handling issues is carried out in partnership with seven other major industry partners worldwide. In a European context, the EI has worked with standards organisations on risk assessment, and the outputs are now accepted environmental guidelines. These examples illustrate the truly international range of the EI's activities and its commitment to working with others for the industry's benefit.

The EI is widely recognised for its role as 'honest broker' – acting as the technical link between industry and regulators such as the Health and Safety Executive and the Environment Agency. This was evidenced recently by the request from the Downstream Oil Industry Forum, chaired by the DTI, for the EI to update its environmental guidelines for petroleum distribution facilities in conjunction with the Environment Agency.

Independence and sound science are key EI values and as the team build the oil and gas industry programme they are also exploring opportunities to make use of their unique skills and value for natural growth in other energy sectors.

As in any industry, technical developments cannot be implemented and economic growth achieved without a strong workforce behind them, and there is growing concern across this industry about where future leadership talent will come from. In response, the EI is delighted to announce a new research project with partners at Norman Broadbent and Deloitte to assess the depth of the problem and propose a plan of action.

As leaders in our industry we have a responsibility to ensure the best available talent is our talent. Through delivering its own training courses and accrediting external learning provision such as university courses, the EI offers a wealth of development opportunities for individuals. Its information services also keep individuals abreast of industry events. Professional recognition – and for engineers the unique opportunity to become a Chartered Petroleum Engineer – is evidence of both individual competence and professional commitment. By supporting academic study of industry-related subjects, the EI also provides the strong link between higher education and business that will ensure that young people have the relevant expertise to embark on a successful career in the sector.

Words of thanks

I would like to thank you all, members and guests, for your support of the EI. By attending IP Week, by contributing to the EI Technical Programme, by participating in regional, national and international activities, by taking-up membership as an individual and as an organisation, by seeking professional recognition, you are part of developing the reservoir of knowledge and expertise – the energy community that the EI so ably exists to foster and expand in its unique position at the heart of our industry. I urge you to continue your involvement and we at the EI will continue to deliver. This is a very firm and fruitful partnership. ●

On the cusp of change

Addressing the IP Week Annual Dinner at the Grosvenor House Hotel, London, Lee Raymond, *Chairman and CEO of ExxonMobil (above), commented on the world's energy needs, looking at where global energy trends are leading and what the implications will be for energy policies and practices in the UK. The following are highlights from his presentation.*

All IP Week 2005 photos: Jim Four

Lee Raymond began by looking out to the year 2030, stating that: 'The three most important elements in how much energy the world will need are population, economic growth and the development and penetration of advanced technologies. As global population increases and economies expand, so will energy needs, moderated primarily by progress made in the efficiency of energy use.'

'By 2030, the world's population will likely be about 8bn people, or 30% higher than today's level. Some 95% of this growth will occur in countries with developing economies. At the same time, we expect continuing economic growth will create a global economy that will be twice the size of today's, further adding to the need for energy. The combination of economic growth and population increases can be expected to lead to a rise in primary energy demand of about 50%.'

'This means that by 2030, overall global energy demand will be the equivalent of about 335mn boe/d. This is a rise from today of more than 100mn b/d – a huge figure. To put this in perspective, a 100mn b/d increase is about ten times Saudi Arabia's current production.'

He continued: 'And let me reiterate that this growth will be higher – considerably higher – if we as energy consumers do not continue to make wise choices and effective investments to improve the efficiency with which we use energy. We estimate that four-fifths of the energy needs in 2030 will be met by fossil fuels, reflecting the scale of these resources, their flexibility in application, and their cost-competitiveness. While large fossil fuel resources exist to meet this enlarged need, when we look more closely into how future energy will be supplied, the challenge of ensuring adequate energy is quite daunting even for those of us who've witnessed our industry's remarkable progress and success over time.'

'Factoring in the natural decline of current fields, about 80% of the oil that will be needed in 2030 will have to come from new production. Finding and producing this energy will obviously be a tremendous challenge – and one that will occupy our industry for at least the next generation.'

Alternatives and the environment

Raymond went on to explain that it was 'very likely that alternative forms of energy will begin to make more of a contribution to energy supply over this period'. However, he explained that it was here that 'an understanding of the scale' was 'so important', stating that the contribution of wind and solar to global energy would 'still be in the 1% range in 2030' as they were starting from a very low base and because the global energy market was so huge.

'What all of this means,' he said, 'and without disparaging the importance of working on alternative energy approaches, is that for many decades the key issue in energy will be how to find and produce enough conventional energy to support global economic activity and prosperity for a growing world population.'

'There will also continue to be important environmental implications that arise from growth in energy. Even so, the size of the world's energy need – and, more importantly, its fundamental contribution to people's well-being – will impose an inevitable reality on efforts to manage the environmental implications of energy use. History shows that economic prosperity is vital to improving living standards and environmental conditions. It is imperative we do not lose sight of this basic understanding, particularly in the policy-making arena where trade-offs must be weighed and hard choices made.'

Europe and the UK

Having painted the energy picture in very broad strokes, Raymond set the stage for a closer look at where ExxonMobil believed energy use will be heading in Europe and the UK.

'Overall, the key change that will emerge is that Europe will provide less and less of its own energy, and will become a larger and larger importer, dependent even more than it is today on the global energy marketplace. This cannot, and should not, be a surprise to this audience.'

'Today, only a few countries – Denmark, the Netherlands, Norway and the UK – are net exporters of either oil or gas. Within a fairly short period of time – perhaps by around the middle of the next decade – only Norway is likely to still be in this position. In the meantime, the import dependence of most other European countries will continue to grow.'

'The UK has, of course, been a net exporter of oil for more than two decades and a net exporter of natural gas since 1997, thanks to a vigorous and successful effort to develop the British sector of the North Sea. But this is on the cusp of change, as local production is in decline and, until recently, exploration activity has been at a relatively low level.'

'Our industry's focus for the UK is to meet the growing demand for energy while moderating the rate of production decline. Doing so will mean ensuring that exploration continues to be conducted and that production from existing

brownfield resources is maximised. For these goals to be accomplished, there must be a willingness to take steps to control costs on remaining production, including those related to taxes and regulatory requirements, as the UK has to compete with other jurisdictions around the world for investment funds.'

'The costs of operating in the UK Continental Shelf are among the highest in the world, and we should not be distracted by the current rise in oil prices, which have as recently as a few years ago been as low as $10/b. While there are some who think that today's prices mean that our industry can, and should, pay higher taxes, I would remind them that ours is a long-term business, and that project lives often exceed 20 years.'

'We have only to look back to the tax changes made in the UK North Sea in 2002 to see the interruption that subsequently took place in exploration. I would note that three years later we are just beginning to see some pick up in confidence and activity. Nevertheless, the trend in production levels is down, and likely to remain so due to geologic reasons.'

'Adjusting to this expected decline in oil production can be fairly readily achieved with additional imports through existing infrastructure. Some new facilities may be needed, but these will not be unusual either in size or character. There may need to be some psychological adjustment to having to rely on the world market for most oil supplies, but the major increase in imports should pose no extraordinary challenges.'

Natural gas story

Raymond went on to explain that the natural gas story was, however, 'a bit different'.

'Even with some new discoveries, we anticipate that gas production in the area around the UK will decline from a current level of about 10 Gcf/d to about 7 Gcf/d by the end of this decade, and then to less than 3 Gcf/d by 2020. Because consumption of natural gas will continue to rise – and will need to, if the UK is to continue to meet its Kyoto obligations and the challenging additional carbon dioxide reduction targets it has set itself – the only option for satisfying this demand will be from a very large and rapid increase in imported gas.'

'There is simply no other logical way forward. Accelerated conservation will be insufficient, a large expansion of nuclear energy would probably be unpopular, expensive and unattainable in the time frame we are considering, and renewable energy simply does not have the scale required.'

'So the UK will now be in rapid transition to being a net importer with growing requirements of both oil and gas, and the increase in gas will require substantial investments. Because this will be a significant change in circumstances and will come about quite quickly, it will mean that this country will have to adjust in a way that has not been necessary for more than three decades. This change in circumstance is now widely understood, and the central challenge is to ensure that government policies promote a business climate that attracts needed energy investments.'

Raymond then asked that, if there was going to be a large increase in imported gas for the UK, where would it come from? 'Fundamentally, there will be four major sources of gas for the UK – mainland Europe (including Norway), Africa, the Middle East and Russia. Gas sources in the Asia-Pacific region are simply too far away to be competitive, although they will obviously influence the global market for gas.'

He went on to explain that Africa and the Middle East are not pipeline connected to European markets, with the exception of gas that flows from Algeria. 'This means that for supplies to flow to the UK from Africa and the

EI Chief Executive, Louise Kingham MEI (centre), chats to Jeroen van der Veer, Chairman, Royal Dutch/Shell Group (left), and Sir John Collins FEI, EI President-Elect (right)

Middle East there will need to be significant investment in new liquefied natural gas infrastructure,' he said.

'This is already in process at Milford Haven in Wales, where ExxonMobil and Qatar Gas have begun construction of an LNG regasification terminal. This terminal will be the access point for the nearly 16mn annual tonne Qatar II LNG project. Additional LNG terminal projects are also well advanced, including the Isle of Grain and a second terminal located at Milford Haven. The sources of the LNG for these projects include Qatar, Egypt, Algeria and West Africa, where new projects have been announced and others are being developed.'

'If these expansions are built, the capacity of the new UK import terminals has the potential to supply about 4–5bn cf/d of market demand by 2020 – which will contribute around 40% of expected UK demand at that time. We also expect that there will be much greater production from gas fields in Russia and the countries of the Former Soviet Union. The gas from these fields will tend to move to European markets through pipelines.'

'With more than 35bn cf/d of new gas that we expect will become available by 2020 from Africa, the Middle East and the Former Soviet Union, it would appear that the UK should be able to meet its natural gas needs through imports.'

'A key consideration, of course, is that the UK will not be alone in needing more gas. Rather, it will face international competition for available supplies.'

Raymond then went on to explain that Europe will have to be competitive in order to attract the increased imported gas that it will need as Asian countries and the US will also be looking for additional gas during this period. Furthermore, when considering ship-borne LNG, there was likely to be a global competitive market place for available supplies.

'The UK and the rest of Europe will, of course, need to pay world market prices for gas, and will also need to encourage the investment in new facilities that will be necessary if the gas is to be made available to consumers,' he said. 'This country is generally to be complimented on understanding the importance of attracting investment. With the background of a stable regulatory environment, the feared supply gap is being addressed as industry participants are rapidly responding with major investment projects. This is a clear demonstration of the value and power of appropriate government policies, especially a reliance on market forces.'

'Of course, one could ask about what would happen if policies were not put in place that will encourage investments and permit consumers to compete for global supplies of gas?'

'No one is likely to run out of energy, but I would expect that there would be even greater demand for energy forms that benefit from existing infrastructure, including oil, coal and nuclear. This would place upward price pressures on these fuels, which will have economic effects. Moreover, limiting the fuel choices for consumers will tend to place a damper on economic efficiency and on the possibilities for optimum economic growth.'

Raymond said that he would also expect that the carbon emissions from the fuels that would be used in place of natural gas would be greater than if the energy had come from natural gas. 'I do not see importantly different political implications simply because most of the added energy will need to come from the same places – namely, the Middle East and the Former Soviet Union.'

'So a failure to accommodate increased use of natural gas will not be a policy catastrophe, but it would put increased pressure on other energy forms and it would complicate further progress toward both economic and environmental goals,' he said.

Addressing potential concerns

Raymond went on to explain that the best way to address potential concerns is 'to help facilitate energy capacity investments through sensible permitting and expansion policies, stable fiscal policies, and to avoid the potentially damaging consequences of attempting to manage energy markets through targeted interventions'.

'The energy market is capital intensive and it is complex,' he continued. 'Change will be slow, and an attempt to manipulate one portion of it can have unexpected and unwelcome consequences elsewhere. When misallocations of resources are signalled in the marketplace through the price system, there will be corrections. Refraining from possibly damaging intervention requires that we retain confidence in the power of competitive markets. Over-regulation can be counterproductive, and we are far better advised to place our reliance on market forces.'

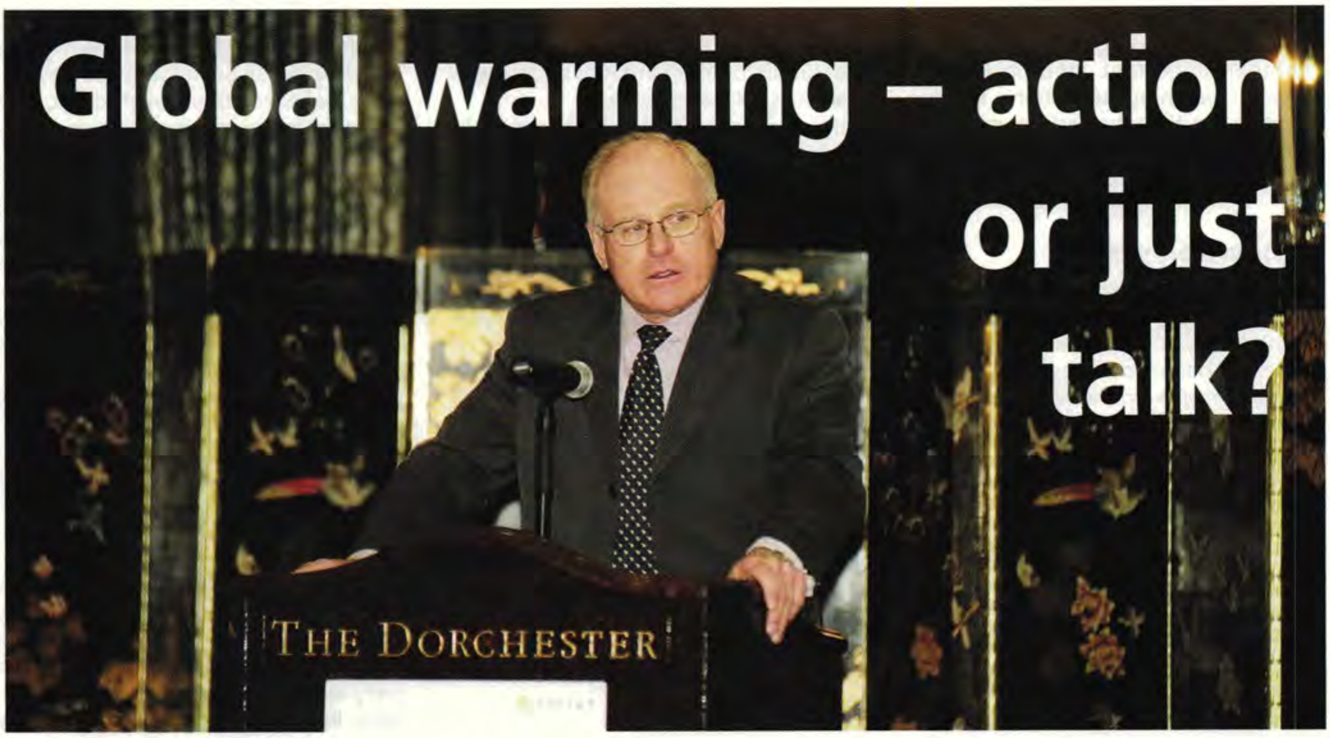
'I also think there will be a need to be realistic about environmental targets. While the political commitment to the Kyoto process and targets is quite strong in Europe, attaining those targets is going to be very challenging, given the energy supply and demand realities. That is why a reality check may be needed regarding the attainment of those targets.'

A period of change

'Overall, the UK, and Europe more generally, is entering a period where the energy structure that has existed for several decades will see increasing and rapid change. Those changes will challenge our industry as we seek to find and deliver needed supplies, and they will challenge European governments as these governments seek to maintain local production and to establish the framework for new energy investments.'

'I anticipate that this period will witness some real tensions. Resolving the matters that give rise to these tensions will take time, money, new technologies, facing up to the hard truths regarding energy, the political courage to enact wise policies, as well as some restructuring of expectations. None of these will be easy, nor will their course run entirely smoothly, but as in other periods our industry has met the challenges that we have faced successfully and we will do so now also.'

Global warming – action or just talk?



Addressing the IP Week Annual Lunch at the Dorchester Hotel, London – and on the eve of the Kyoto Protocol entering into force – Sir John Collins FEI, *Chairman of the DTI/DEFRA Sustainable Energy Policy Advisory Board (above), talked on the topical issue of global warming. The following are highlights from his presentation.*

Sir John Collins began by stating that the issue of global warming was a very 'real' one, warning that action was required today in order to avoid 'catastrophic' regret in 20 to 30 years' time. He said that, 'as a simple businessman', he had become 'passionate' about seeing a plan that would 'deal with global warming'. That said, he went on to state that: 'We must be careful not to blame every climatic hiccup on global warming, because I just don't believe that to be true, and it will damage credibility.'

He continued: 'As a businessman, any plan must have a business discipline and, namely, must be affordable. In being affordable we must clearly ensure that the competitiveness of the UK is not compromised. Secondly, it must be acceptable to society and, in being acceptable to society, security of supply is vital – politicians dare not let the lights go out. Therefore, any plan must cope with peak demand, even if it only arises once every five or 10 years. Security of supply is clearly very much a UK issue as we move to importing, in the first instance, gas, to be followed by oil.'

'Any plan that deals with global warming is unlikely to have real rewards for at least 20 to 30 years. You, as oil people, are used to planning with that sort of horizon. Politicians are not. It is extremely unusual, in my experience, to have any commitment from politicians to a course of action that doesn't produce very rapid results. So where are we?'

'We have the rare experience of UK leadership – and the cynics would say UK leadership without US support. We have in the UK an energy plan designed to deal with global warming in what we believe to be an affordable way and which will also ensure security of supply. My plea to you all during this IP Week is to critique the plans with the intention of helping us to improve, but not derail, the plan.'

Stimulating discussion

To stimulate this discussion, Sir John offered the audience his personal view on how the balance sheet on the energy plan currently stacks up.

'Always start with the positives,' he said. 'The commitment and consistency to the plan is, to me, surprising in political terms. But I can tell you that the commitment from No 10 to tackle global warming is surprisingly strong, even in the absence of American support. And, as many of you know, the Prime Minister will use the presidency of the G8 and of the EU this year to be offering leadership in this area. My discussion with opposition politicians here indicates no major differences in plan – there will be some fine-tuning and some different challenges which are healthy, but I believe there is a strong probability of consistency.'

'The government will also review its climate change programme, with the results coming out sometime through the first half of this year. EU emissions trading, which is just about to begin, is very important to the success of this programme. It will put a price on carbon dioxide, it will give a strong incentive for companies to be reducing their emissions, with a commercial timespan to be trading.'

He went on to state that the ratification of the Kyoto Protocol by Russia was 'another important step in getting Europe marching together', but he pointed out that the task remained of persuading the US, China and India to come on board.

Renewables issue

Sir John then turned to the topic of wind generation, which he regarded as a 'major issue'. He stated that while there had been blockages, such as planning permission, to the development of wind farms in the UK, these were 'being worked on' and 'the attitude of the regulator' was 'now fair, if not encouraging'. As a result, he felt that this particular area was 'developing well'.

However, he pointed out that there was 'also very strong opposition and antagonism to the level of wind farms intended in the plan' and that there were some 'very strong pressure groups active to derail the totality of wind generation'. 'The importance of negative sentiment is a very important aspect in avoiding the debate around wind farming being allowed to spill over and spoil the whole of the energy plan,' he said.

Sir John went on to ask the audience to 'argue more strongly' for 'commercialisation' of other areas of renewables – such as tidal and biofuels.

He then questioned whether the UK could deliver its energy plan with an ever-dwindling nuclear capacity and asked how this important issue should be addressed. He urged proponents for nuclear to 'come forward' with a proposal to build a nuclear plant in the UK, with an appropriate risk assessment, to see whether the government approves it. 'To the best of my knowledge there is no such request at the moment and, until there is, it's jolly hard to test under what conditions nuclear would be approved,' he stated.

He went on to say that: 'You don't need to take a course at Harvard to see that if the current 20% of electricity generation [by nuclear in the UK] moves to 2% in the next decade or so, it's going to add to the challenge of reducing CO_2 [carbon dioxide] emissions,' he said.

Energy efficiency

Sir John then moved to the topic of energy efficiency, which he believed to be 'a harder part of the equation than the supply side', partly because it required a major change of attitude to conserve energy rather than use it freely, 'which we've all been taught to do'.

He believed the government was 'trying hard' to tackle this issue in the domestic arena – with planning permissions for domestic and industrial buildings being reasonably well structured to deliver energy efficiency. However, he pointed to two areas that politicians were 'very scared of tampering with' and both of which were 'extremely important' – road transport and air transport – areas which, in Sir John's personal view were 'currently being fudged'. 'Somewhere, somehow, both these areas have to be addressed in a manner that will deliver, but will not also be political suicide for whatever government tries to bring them forward,' he said.

Sir John concluded by saying that: 'A good start has been made by industry, even better than I would have hoped for – but it's very early days. Each and every one of you here today can seriously influence the outcome. It is my argument that the way in which you do that will greatly affect your own credibility – both to government and the public. I wish you well.' ●

Oil and gas on show

The IP Week 2005 Exhibition took place alongside the events at One George Street, London, throughout IP Week. Kim Jackson *reviews some of the latest news from the exhibitors.*

All IP Week 2005 photos: Jim Four

All conference and seminar breaks during the IP Week programme at One George Street were held in the exhibition hall, providing delegates with an ideal opportunity to look around the IP Week 2005 Exhibition.

Exhibitors included Ashurst, the Centre for Global Energy Studies (CGES), Charles River Associates, the International Energy Agency (IEA), Norman Broadbent, OILspace, Oxford Princeton Programme, Patsystems, UK Trade & Investment, World Energy, the World Petroleum Congress (WPC) and, of course, the Energy Institute.

Online developments

A number of the exhibitors had news to tell, including Patsystems – the global supplier of electronic trading technology – who has created an exchange-specific adapter for the International Petroleum Exchange (IPE) in London and has passed all IPE conformance tests. The IPE is Europe's leading energy futures and options exchange, trading over \$2bn in underlying value every day, and in recent months has seen record volume growth for electronic trading in gas oil and Brent crude.

Users of Patsystems' J-Trader front-end can now trade contracts in Brent crude, gas oil, natural gas and associated crack spreads. In connecting to the IPE, Patsystems has increased its global coverage to more than 30 exchanges.

David Hall, Director, Product Marketing, told *Petroleum Review* that 2005 was 'the year of the commodity' and that Patsystems was planning a continued expansion of its connectivity by adding further exchanges during the year. The company is also planning to increase the power and versatility of its trading applications through new technologies that will be progressively released from early 2005 onwards. [For more information on Patsystems' products and services, visit **www.patsystems.com**]

Also exhibiting, was OILspace [**www.oilspace.com**] – a leading global provider of advanced real-time web services applications and integration for oil, gas and petrochemical trading, marketing and supply operations. Christopher Sternberg explained that the company's supply chain solutions now run through nine of the world's 10 largest oil companies and serve nearly 300 clients of all sizes and roles within the energy supply chain.

Russia has been a particular area of focus over the past 18 months, with the company developing customised supply chain and logistics solutions for both Lukoil and TNK-BP in a bid to 'improve margins and profits'. Indeed, industry estimates that such solutions can offer between 20–70 cents/barrel cost savings in the supply chain.

China will be the next focus of attention, according to Sternberg, as it is a vast market with 'similar challenges' to those found in Russia – with the various control elements of the supply chain, from field to export terminal, widely distributed. As a first step, OILspace has established a new development centre at Shanghai, China, and launched a localised Chinese language website to support its customers. The company also plans to develop its business in the burgeoning market of India. Europe and the Middle East, too, are reported to have shown interest in supply chain solutions available, as infrastructure is widespread and the need to connect business assets globally without deploying costly data centers, hardware and staff to support them is necessary, reports Sternberg.

Also new for 2005, will be the development of a 'shipping marketplace' that will allow BP to electronically communicate with the international bunker community.

Shaping the energy future

The World Petroleum Council (WPC) was busy promoting its 18th Congress that is to be held in Johannesburg, South Africa, on 26–30 September 2005 – the first time in its 74-year history that the Congress will be held on the African Continent. The theme of this year's Congress is 'Shaping the Energy Future: Partners in Sustainable Solutions.'

The event is being hosted by South Africa's state-owned PetroSA, with co-host sponsors being the national oil companies of Algeria, Angola, Libya and Nigeria – Sonatrach, Sonangol, National Oil Corporation Libya and the Nigerian National Petroleum Corporation. Featuring a number of keynote presentations and a wide-ranging technical programme, the 18th Congress will also act as the forum for the presentation of the WPC 2005 Excellence Awards. [For more details about the 18th Congress, visit **www.18wpc.com** For more information on the Awards, visit **www.world-petroleum.org**]

WPC was also pleased to recently announce that Morocco, Kenya, Macedonia and Lithuania have become member countries.

Measurably different

Norman Broadbent – a leader in the executive search market – was also exhibiting at One George Street. Jon Glesinger, Managing Director, Energy & Natural Resources, told *Petroleum Review* that at the end of 2004 the company had commissioned a leading market research company to carry out an in-depth survey on executive search in the UK and changes companies would like to see in the future. 'As a result, we have taken action and fundamentally altered the way we work,' he said, 'a decision which clients and candidates tell us makes Norman Broadbent "Measurably Different" in the market.'

'We recognise that every client and candidate is unique, with their own needs and challenges. We know this because we've made it our business to understand each one in depth and breadth. We adopt a penetrating approach to recruitment that goes beyond the norm, enabling us to tailor a precisely fitting solution to each assignment.'

'The energy and natural resources sector is like no other, both in terms of global scale and financial strength. As such, recruiting within and into the sector calls for a true understanding of

the changing commercial, regulatory and economic drivers within key markets.' [For further details, visit **www.normanbroadbent.com**]

World news

The International Energy Agency (IEA; **www.iea.org**) stand was busy promoting a range of publications, including its latest (February 2005) *Oil Market Report*, which stated that global demand is increasing faster than expected. Oil consumption is predicted to reach 84mn b/d this year, some 120,000 barrels (1.8%) more than the agency forecast in January 2005. The agency also said inventories of oil and fuel held by industrialised nations fell to just 51 days of demand in December 2004.

Demand in China, the world's second-largest oil consumer after the US, increased 15.6% in 2004 and is projected to rise 6.3% this year. This compares with an average 0.6% increase for 2005 among members of the Organisation for Economic Cooperation and Development (OECD).

Meanwhile, 2005 production from non-Opec countries is expected to be about 175,000 b/d less than earlier forecasts, the IEA said. Russia, the world's second-largest oil exporter, is forecast to produce 9.58mn b/d in 2004, a fifth less than the IEA predicted in January.

Elsewhere, Cheryl Burgess, Regional International Trade Advisor, Energy Sector, Business Link for Norfolk, was on hand to outline the work of UK Trade & Investment [**www.uktradeinvest.gov.uk**] – the government organisation that provides integrated support services for UK companies engaged in overseas trade and foreign businesses focused on the UK as an inward investment location. The organisation brings together the work of teams in British embassies overseas and government departments across Whitehall. In England, UK Trade & Investment services are delivered through 45 Business Links and other partners including Regional Development Agencies and Chambers of Commerce, coordinated by nine regional International Trade Directors. The devolved administrations in Scotland, Wales and Northern Ireland have their own arrangements for local delivery of services.

Focus on training

In addition to providing information, advice, training, grants and organising trade missions, UK Trade & Investment has also supported the development of GTEP (Global Training and Education Partnership), launched at the end of 2004. GTEP is an industry sector partnership between the Association of British Offshore Industries (ABOI), British Oil Spill Control Association (BOSCA), Energy Industries Council (EIC), Pipeline Industries Guild (PIG) and the Society of British Gas Industries (SBGI). The new initiative aims to develop and coordinate a promotional programme for the training and education segment of the oil and gas industries, and help facilitate their entry into international markets. [For more information, visit **www.gtep.org.uk**]

Meanwhile, the Oxford Princeton Programme – which completed a management buyout in September 2004, giving Clara Lippert, President, full controlling interest of the company – was busy promoting its range of training courses for the oil, gas and energy sectors, including its most recently developed 'Electric Power Horizons: Using Scenario Planning to Manage Uncertainty in Energy Strategy Analysis'. [For more details, visit **www.oxfordprinceton.com**]

Among the other exhibitors was the Ashurst law firm, whose energy team comprises over 60 energy and natural resources lawyers worldwide. The company also sponsored the Tuesday 15 February seminar entitled 'Future opportunities in the Middle East and North Africa' – see review in next issue. [For more details about Ashurst's legal services, visit **www.ashurst.com**]

The Centre for Global Energy Studies [**www.cges.co.uk**] was also promoting its range of reports, studies, conferences and seminars, including its 22 March 2005 seminar entitled 'National Oil Companies in the Face of Changing Market Conditions', at which the Iraqi Minister of Oil, HE Thamir Ghadhban, is expected to speak. ●

New strategies target Philippine energy sector

The Philippine government plans to adopt new strategies to attract private investment to take over the state-run electricity industry and finance development of the country's sizeable indigenous energy resources, reports David Hayes.

Plans to expand energy supplies to the Philippines include the development of domestic coal, natural gas, geothermal, hydroelectric and potentially large renewable energy reserves. Imported energy supplies will also remain important in the Philippine energy mix unless large, as yet undetected hydrocarbon resources are discovered. Oil product and coal imports will remain important energy sources well in to the future, while plans call for the launch of an LNG import programme to expand power generation and increase clean energy supplies to major cities and industrial zones.

According to Department of Energy (DoE) forecasts, the Philippines was due to achieve 55.5% self-sufficiency in its total energy requirement of 274mn bfoe (mn barrels of fuel oil equivalent) in 2004, with indigenous energy supplies totalling 152mn bfoe while imported energy supplies were 122mn bfoe. Rising natural gas production from the Malampaya gas reserves is believed to have resulted in a 7% decrease in imported oil consumption and also helped reduce imported coal use during the past year.

In spite of the reduced reliance on oil, imported oil products remain the largest source of primary energy – accounting for 38.7% of the total energy mix; while coal accounts for 10.5%, geothermal energy 7.9%, natural gas 6.7% and hydroelectric power 5.3%. Other renewable energy sources, including fuel wood, charcoal, bagasse, microhydro schemes and wind power, account for the remaining 30.9% of energy use.

By 2013 the government forecasts that the Philippines' primary energy requirement will increase 46.3% to 401mn bfoe. Indigenous energy use will account for 233mn bfoe of this demand, while imported energy use will meet the remaining 168mn bfoe. Plans call for the proportion of self-sufficiency to increase to 58.2% by the end of the 10-year period.

Imported oil products will remain the largest source of energy, accounting for 33% of the primary energy mix. The natural gas share of primary energy is expected to rise to 15.1%, while coal will move up to 14.2%. Geothermal energy is forecast to remain stable at 7.6%, as will hydroelectric power at 5.2%. Other forms of renewable energy will supply the remaining 24.9% of energy use, down about 5% from the current proportion that fuel wood, charcoal and other sources provide.

The residential sector is the largest consumer of energy in the Philippines, using 40% of primary energy supplies according to DoE statistics. Transport is the next largest use, accounting for 31.4% of primary energy, followed by industry 14.9%, agriculture 9.3% and commerce 8.4%. Residential energy consumption is forecast to remain the largest use of energy in 2013, growing by 22.4mn bfoe during the intervening period, followed by transport use, which will increase by 28.5mn bfoe, and industrial use, which is predicted to grow by 13.6mn bfoe.

Electricity generation

Electricity generation remains the major use of coal and gas use in the Philippines and a significant, though declining, share of oil consumption. To promote development of clean energy, the government has been encouraging private investors to convert old or retiring oil- or coal-fired power stations to burn natural gas.

In 2003, natural gas accounted for 35% of the Philippines' total 37,535 GWh power generation, second only to coal, which represented 38% of power production. Hydropower and oil-fired stations each accounted for 10% of power generation, while geothermal plants produced 7%.

Coal-fired stations are the largest in terms of installed capacity, accounting for 32% of the Philippines' dependable 11,100 MW of installed generating capacity. Natural gas-burning units represented 25%, oil-fired units 20%, hydropower schemes 16% and geothermal plants 7%.

By 2013, the nation's installed electricity generating capacity will almost double to 21,030 MW. By then, oil-fired stations will have been reduced to 2,540 MW – down from 3,615 MW in 2003. Expansion of generation capacity using other fuels is likely to rely on gas, coal, hydropower and geothermal energy as these stations are larger in size than power plants based on the Philippines' other planned generation sources.

Most power plants will be privately owned by 2013. At least 70% of state electricity sector assets are due to be sold off by the end of 2005 as the government plans to recover the cost of absorbing the debts of bankrupt state power utility Napocor. However, power sector analysts believe that a recent series of court decisions reversing utility electricity tariff increases could make it difficult for the government to sell the bulk of its power sector assets quickly, due to possible investor concern over their ability to set profitable tariffs.

Growing gas role

Natural gas is poised to play a bigger role in the Philippines' energy picture in the future. At present, almost all natural gas consumed is produced at the Malampaya gas field offshore northern Palawan, which is piped to Batangas in southern Luzon to fuel three power plants – the 1,200-MW Ilijan, 1,000-MW Santa Rita and 500-MW San Lorenzo facilities that supply electricity to metro Manila and the surrounding region.

The state-run Philippine National Oil Company (PNOC) is currently preparing to launch a scheme estimated to cost between \$80mn and \$100mn to construct a gas transmission pipeline from Batangas in the south of Luzon island, where Malampaya gas comes ashore

through a subsea pipeline, to Manila. Due for completion by 2007, the pipeline will carry indigenous gas from the Malampaya field and other potential nearby reserves.

PNOC's gas pipeline is due to terminate at Sucat power plant on the outskirts of Manila. The moth-balled 850-MW oil-fired power plant is due for privatisation and could either be converted to gas-fired generation or knocked down and rebuilt as a combined cycle plant of 600 MW to 900 MW capacity. PNOC is expected to hold a stake of at least 59% in the pipeline project, while a number of foreign companies are reported to have shown interest in being selected as project partner.

'The Department of Energy does gas planning and policy. We gave the pipeline permit to PNOC as they were the only ones to apply,' commented a DoE official. 'Our target is for the pipeline to be in Manila by 2007. Things should get moving to complete this.'

The Batangas-Manila gas pipeline will also be used to transport LNG in the future, planned for import through the proposed Calaca LNG terminal. The facility is expected to import 1mn t/y of LNG from 2015.

Other gas sector development proposals include building LNG terminals at Marveles and Limay, north of Manila Bay, to supply power plants and feed into the proposed Manila piped gas grid. Both LNG terminals would be sized to handle 1mn t/y initially.

Piped gas use is also expected to develop in other parts of the Philippines. Plans include setting up LNG import facilities in Cebu, using either LNG or CNG. In addition, LNG import facilities are proposed for Mindanao – possibly two terminals, located either side of the island and connected by a cross-country pipeline to ensure security of supply.

Above: Edsa highway, Manila, Philippines

Right: Jeepney taxi in front of overhead railway station, Manila

Coal consumption

Meanwhile, DoE long-term plans call for a large increase in domestic coal consumption, largely to meet growing power generation fuel requirements. The DoE targets project that consumption of domestic coal could grow fourfold by 2014, to reach 8.4mn t/y. Power plants will be built in a number of locations close to coal reserves in Northern Luzon and the Visayas region. Small and medium-size coal-burning power plants will be installed, ranging from 50 MW to 200 MW in capacity.

Coal consumption was forecast to reach about 8.1mn tonnes in 2004, up marginally from 8mn tonnes in 2003. Power generation was the main market last year, consuming about 6.3mn tonnes and accounting for about 76% of the Philippines' total coal use. Most of the remaining coal was used by cement factories.

Imported coal totalling 5.8mn tonnes accounts for about 74% of total coal supplies, while the balance of 2.3mn tonnes is locally mined. About 4.2mn tonnes of imported coal was used in 2004 for power generation, representing about 65% of all coal used by the electricity industry. The cement industry used about 1.3mn tonnes, accounting for 80% of total coal use. The other 300,000 tonnes of imported coal is used for various purposes, including fuel for alcohol distillation, metal smelting and sintering processes, paper making; also for chemical and fertiliser production.

'The main issue for coal is environmental. The public has the perception that coal is dirty,' the DoE official said. 'It could be that they are not aware of clean coal technology. It is the same problem all over the world. We are doing public relations to improve coal's image. The problem is power genera-

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Largest-ever investment levels target new production

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

Nexen is an independent, global energy and chemicals company. Its core business activities include the exploration, development, production and marketing of crude oil and natural gas in the US, UK, Yemen, Canada, Nigeria, Australia and Colombia.

The company's strategy is to grow in the Gulf of Mexico, the North Sea, offshore West Africa, the Middle East and Alberta's Athabasca oil sands. In order to achieve this goal, this year sees Nexen embarking on what will the largest development and exploration capital programme in its history. By the end of 2005, cumulative investment in multi-year development projects, with production start-up at least one year in the future, will reach over $4bn.

Highlights for 2005

Full production from block 51 in Yemen is expected in late 2Q2005, while the Long Lake project in Canada and the North Sea Buzzard field development remain on schedule to begin production in late 2006. High-quality exploration programmes are also planned in the Gulf of Mexico, West Africa, North Sea and Yemen. In addition, Nexen plans dispositions of $1.5bn to reduce company debt.

This year, Nexen plans to invest approximately $2.6bn in capital projects – an increase of over $700mn compared to 2004. Less than 20% of this capital will be directed toward sustaining production and cash flow from the company's producing oil, gas and other assets in the short term. The balance will be invested in longer-cycle time growth opportunities that will begin contributing production and cash flow in 2006 and beyond.

The Syncrude Stage 3 expansion in Canada is expected to add an incremental 8,000 b/d of production net to the company's 7.23% interest in the joint venture, following completion in early 2006. Activities next year will focus on completing and commissioning the upgrader expansion and increasing bitumen production capacity.

Meanwhile, at Buzzard, the company plans to invest approximately $530mn on development drilling, pipeline installation and facility construction. This development is on budget and on schedule to commence production in late 2006, with Nexen's share of production ramping up to 80,000 boe/d during 2007. Following the recent purchase from EnCana, Nexen is now the field operator, holding a 43.21% stake. The Buzzard field is located in the Outer Moray Firth, central North Sea, straddling two licences – P986 in blocks 19/10 and 20/6, and P928(S) in blocks 19/5a and 20/1S).

Nexen also plans to invest an additional $60mn to evaluate and commence development of a number of smaller discoveries on its North Sea acreage. These discoveries will contribute to the expected doubling of non-Buzzard production in the North Sea by 2008. The first of these projects – Farragon – is due onstream in late 2005, with Nexen's share of production reaching approximately 3,000 to 4,000 boe/d in early 2006.

The Long Lake project also remains on schedule. Drilling of the SAGD (steam assisted gravity drainage) wells commenced in late 2004 and will continue throughout 2005, with facilities planned to be completed in late 2006 and the upgrader in 2007. The upgrader is expected to come onstream in 2H2007, with synthetic crude oil production ramping up to approximately 60,000 b/d. Nexen has a 50% interest in the project.

Exploration overview

Nexen expects to invest half of its 2005 exploration capital in the Gulf of Mexico, where it plans to drill at least eight high-potential exploration wells. These include testing deep-shelf gas prospects and two types of deepwater plays, those near existing infrastructure and sub-salt prospects.

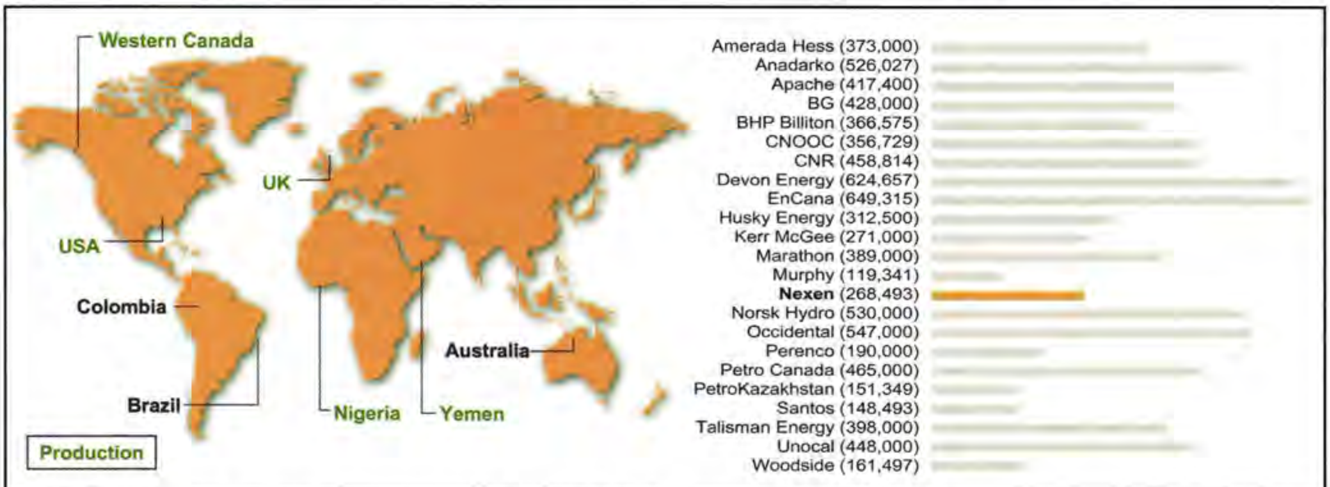

Figure 1: Nexen's core activity and average production (boe/d) in 2003

In Canada, Nexen will continue to focus on large unconventional resource type opportunities. The company expects to establish commerciality of its Upper Mannville CBM (coal bed methane) pilot project at Corbett in 2005, setting the stage for full field development, and continue the evaluation of other Upper Mannville and Horseshoe Canyon CBM prospects. In addition, the company plans to continue with a number of enhanced oil recovery (EOR) pilot projects in west-central Saskatchewan. These projects are evaluating VAPEX extraction and alkaline flood technologies for increasing recovery factors from the company's extensive heavy oil properties.

In the North Sea, there are plans to drill, complete and tie-in five development wells in the Scott/Telford area, work-over several existing wells and de-bottleneck and upgrade production facilities on the Scott platform.

Meanwhile, in Yemen, the BAK-B field will initially be developed with five wells and is due onstream in late 2005. This will allow production from block 51 to be maintained at approximately 25,000 b/d through 2007. Nexen also envisages additional growth through continued exploration success on the block, in which it has an 87.5% operated working interest.

The Yemeni Masila block continues to generate exceptional value, Nexen reports. By the end of 2004, the company will have produced approximately 80% of Masila's expected reserves and have generated more than $1.5bn of free cash flow, net to its interest. As it continues to deplete the remaining reserves, Nexen expects to recover in excess of $1bn of additional free cash flow prior to the expiry of the primary term of the production sharing contract in 2011. The Masila fields are maturing and Nexen is now slowing the pace of its drilling programme to between 20 to 40 wells per year to ensure recovery of the remaining reserves in the 'most economical and prudent manner'.

Offshore Nigeria, the Ameena-1 exploration well on OML-115 encountered high quality reservoir sands. However, the sands were wet and the well has been abandoned. A second well will test a separate structure on the block in mid-2005. Nexen also plans to test a number of new structures on OPL-222 in 2005.

The K-1 (Zorro) exploration well on block K offshore Equatorial Guinea found non-commercial quantities of hydrocarbons and has also been abandoned. Multiple prospects have been identified on this 1.1mn-acre block, and the drilling of the next exploration well is expected early in 2005 once a final location has been determined. Nexen has a 50% operated working interest, with Repsol Exploracion Guinea holding the remaining interest.

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

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tion. Indications are that people object to coal-fired plants.'

Expanding options

Meanwhile, plans to expand domestic energy production include development of the Philippines' large under-utilised renewable energy resources. In fact, the Philippines already relies on renewables for a substantial proportion of energy supply due to the existing development of geothermal and hydro-electric power.

Government plans call for renewable energy consumption to be doubled by the year 2013. In achieving this target, the government expects the Philippines to become the world's largest producer of geothermal energy, overtaking the US. Currently, geothermal power plants totalling 1,932 MW are installed across the Philippines. Geothermal energy is the third largest source of electricity after coal-fired and gas-burning stations, generating about 9,200 GWh of electricity in 2003. In fact, many geothermal plants require overhauling and consequently operate below their maximum potential.

In 2004, the DoE offered ten geothermal sites for development – totalling about 510 MW generating capacity potential. Eventually Marubeni was the sole bidder for a 20-MW optimisation project at Mount Apo, where Marubeni/PNOC already operate a 108-MW geothermal power plant. Mitsui and local company CPL both bid for the 40-MW Rangas Tananaon project, which will expand the Bac-Man geothermal field use.

Consequently, eight plots did not attract bidders – although these could still generate interest among carbon trading investors. The DoE is planning a second bid round in 2005 for various sites where resources totalling 450 MW are available.

'This was the first geothermal contracting round. The second round will have some additional fields,' the source said. 'We have a lot of geothermal resources, but a lack of investment. Upstream project investment permits only 40% foreign participation, but no Philippine companies are willing to put up 60%. PNOC has done the most, while Unocal has done two projects at Bac-Man and Tiwi for steam generation.'

'Napocor is being privatised – so all assets must be sold. Geothermal and power plant assets should not be sold separately from the geothermal fields, so Unocal is trying to get NPC plants and then a service agreement with DoE to do more exploration. Most geothermal resources are under-utilised because the facilities need refurbishing, but Mindanao is at full capacity because it is new,' continued the source.

Among other renewable energy targets the government has been planning, the Philippines is set to become the leading wind energy producer in South-east Asia. In addition, the nation's hydropower capacity will be doubled by 2013, which will involve adding hydropower plants totalling a further 2,950 MW in capacity. Production of biomass, solar energy, ocean energy and other resources will also be developed to serve more remote communities.

Wind power resources based on satellite data are estimated at about 74,00 MW, while the Philippines' ocean thermal energy conversion potential is 170,000 MW – mostly from marine currents running along the northern and western flanks of the Philippine archipelago. Actual development of these resources is likely to be gradual, with mostly small sites being developed to supply local communities.

Photos: David Hayes

No way out

As the oil sands expand dramatically over the decade, existing pipelines will find themselves overloaded. How will producers get their product to market? asks Gordon Cope.

Canada possesses an abundance of oil – some 175bn barrels of reserves – second only to Saudi Arabia. Unfortunately, it is not the light, sweet kind that flows out of the ground when pierced with a well, but the thick, gooey sort mixed with mud and sand. The oil sands located in north-east Alberta around Fort McMurray are largely exploited through the use of surface mining. Increasingly, deposits that lie too deep for surface mining (some 80%) are recovered using in-situ techniques such as steam assisted gravity drainage (SAGD), in which steam is injected into the ground in order to decrease viscosity and encourage the bitumen to flow and be pumped to the surface.

For the last few years, major petroleum companies have been investing an average of C$6bn annually into production facilities. The National Energy Board (NEB) reports that oil sands production hit 1mn b/d in 2004 – about 40% of Canada's production of 2.5mn b/d. Three major projects account for the bulk of output:

- Syncrude, owned by Canadian Oil Sands Trust, Imperial Oil, Petro-Canada and Nexen, produces an average of 250,000 b/d of light, sweet crude oil called Syncrude Sweet Blend (SSB) from its Mildred Lake and Aurora facilities. A C$7.8bn expansion, Syncrude 21, is now in the third stage. It will boost output by 100,000 b/d, to 350,000 b/d, by 2006.
- Suncor produces some 225,000 b/d of synthetic crude after its latest expansion. In addition, it currently produces around 11,000 b/d from the partially completed Firebag project, an in-situ operation located 40 km north-east of its main facility. When completed, Firebag should add 35,000 b/d, boosting total production to 260,000 b/d in 2005.
- The Athabasca Oil Sands Project (AOSP), owned by Shell Canada, Chevron Canada Resources and Western Oil Sands, extracts 155,000 b/d from its Muskeg River mine. The bitumen output is mixed with diluents, and the 'dil-bit' slurry is transported 490 km by pipeline to Edmonton, where it is upgraded to refinery feedstock.

Photo: www.syncrude.com

Syncrude plans 350,000 b/d production by 2006

All three intend to continue with their expansion. AOSP plans to retool its Muskeg Mine and Scotford upgrader to boost production to between 270,000 and 290,000 b/d by 2010. Suncor hopes to expand output to as much as 555,000 b/d, while Syncrude will increase production to around 550,000 b/d by 2015.

In addition, the Canadian Association of Petroleum Producers (CAPP) estimates that C$30bn will be spent on new projects and infrastructure in the coming decade. Canadian Natural Resource has the go-ahead to build the C$8.5bn Horizon oil sands project that will produce 232,000 b/d of synthetic crude by 2008, while Imperial Oil and ExxonMobil want to build an C$8bn open pit mining operation at Kearl Lake that could see first production of 100,000 b/d in 2007 (with the potential to expand to 200,000 b/d at a later date). Husky Energy's C$500mn Tucker oil sands project will use steam to produce 35,000 b/d. Shell Canada has received regulatory approval for Jackpine, a 200,000 b/d project near the Muskeg River mine.

All of this is good news for Canadian oil production. Even though conventional oil is declining, CAPP still expects that, by 2015, Canada's overall production will increase by 1mn b/d to around 3.5mn b/d.

To market, to market

When it comes to markets, there won't be any shortage of takers. Refineries throughout the American Midwest and Rocky Mountains have traditionally relied on domestic supplies of heavy sour crude, but declining production has left them seeking new sources. California is suffering a similar fate as its local supplies of heavy sour crude slowly decline. Further afield, Asia consumes some 15.5mn b/d of heavy sour, primarily from the Middle East, and is seeking alternate sources in order to decrease reliance on the volatile region.

Only one major impediment stands in the oil sands' way. Currently, several pipeline systems, including the Corridor and Athabasca, move bitumen, dil-bit and refined crude out of the Fort McMurray region to the major lines that reach markets in the Rocky Mountain and Midwest US states, and eastern Canada. More regional pipelines in Alberta are planned. However, new, major lines heading out of the province will be needed to avoid transportation bottlenecks. 'In order to export, they will need additional capacity in the next three to five years,' says Onno Devries, General Manager, Oil Sands and Markets for CAPP. Four significant pipeline projects have emerged – Southern Access, Spearhead, the Trans Mountain Expansion (TMX) and Gateway.

Of the four, the first two are already progressing. Southern Access is the initiative of Enbridge, based in Calgary, which operates the major oil pipeline heading east. A new, 1,000-km crude pipeline will emanate from its existing terminal at Superior, Wisconsin, and head south to the Wood River hub in southern Illinois. The 24- or 32-inch diameter pipeline will cost an estimated C$550–650mn and have an initial capacity of 250,000 b/d. In addition, Enbridge has recently purchased from BP a pipeline that runs from Cushing, Oklahoma to Chicago. Under the Spearhead project, Enbridge will reverse the flow in the line to carry oil sands crude further south than ever before into the American market. 'It will be pushing closer to the Gulf Coast,' says Devries. While initial amounts will be small, approximately 60,000 b/d, the pipeline has the capacity to handle 160,000 b/d.

The two remaining projects are in preliminary stages. The Trans Mountain pipeline, owned by Calgary-based Terasen Pipelines, is the only West Coast outlet for Western Canada's crude. Eleven pumping stations move approximately 200,000 b/d of crude and refined petroleum products through a 1,200-km, 24-inch pipeline that traverses the Rocky Mountains and then runs down the Thompson River valley to Westridge Marine Terminal in Burnaby, British Columbia (near Vancouver). A spur line at Sumas, British Columbia, carries crude and condensate to refineries in Washington State.

In order to serve the Asian and California markets, Terasen has proposed a C$2.5bn expansion of the Trans Mountain system that would potentially quadruple capacity to 800,000 b/d. The expansion is based upon looping the existing system in three phases. Over the course of four years, a new, 30-inch pipeline would be added in sections. It would have a capacity of 500,000 b/d and be dedicated to handling crude only. The capacity of the 24-inch legacy pipeline would be expanded to over 300,000 b/d, and carry refined petroleum products.

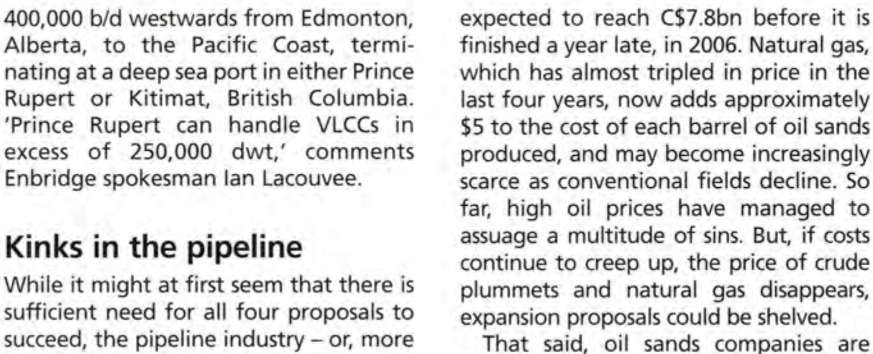
However, Terasen's plan has one shortcoming – its Westridge terminal can handle carriers no larger than 100,000 tonne capacity. For very large crude carriers (VLCCs), a deepwater port is required. In order to overcome this obstacle, Enbridge has proposed the Gateway project, a 1,200-km, C$2.5bn, 30-inch liquids pipeline that would carry 400,000 b/d westwards from Edmonton, Alberta, to the Pacific Coast, terminating at a deep sea port in either Prince Rupert or Kitimat, British Columbia. 'Prince Rupert can handle VLCCs in excess of 250,000 dwt,' comments Enbridge spokesman Ian Lacouvee.

Oil sands – sticky stuff to move

Kinks in the pipeline

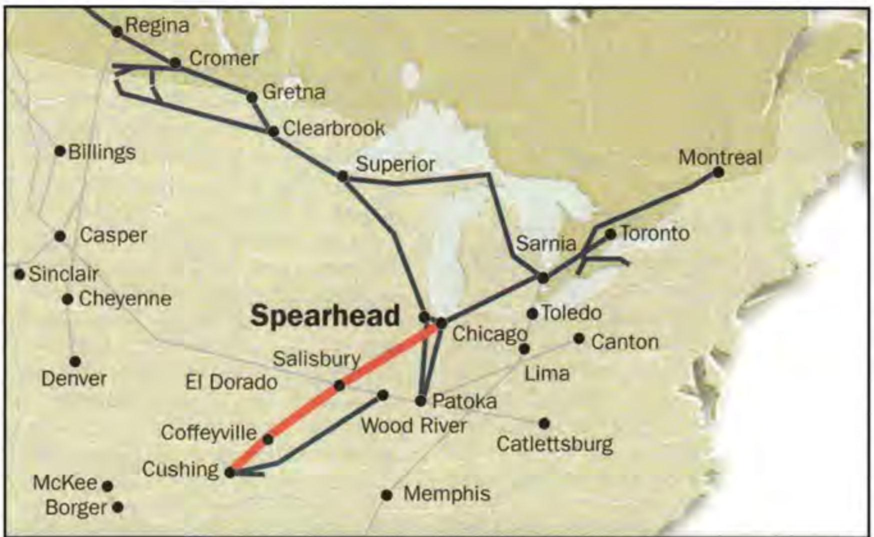
While it might at first seem that there is sufficient need for all four proposals to succeed, the pipeline industry – or, more specifically, its bankers – remain cautious. First and foremost is the assumption that there will indeed be an extra 1mn b/d production looking for a ride in the next decade. This may be rash. Recent oil sands expansions have run afoul of cost overruns. Syncrude's Stage 3 project, for instance, was originally budgeted at C$4.1bn in 2001. Thanks to soaring labour costs, transportation bottlenecks and engineering changes, the cost is expected to reach C$7.8bn before it is finished a year late, in 2006. Natural gas, which has almost tripled in price in the last four years, now adds approximately $5 to the cost of each barrel of oil sands produced, and may become increasingly scarce as conventional fields decline. So far, high oil prices have managed to assuage a multitude of sins. But, if costs continue to creep up, the price of crude plummets and natural gas disappears, expansion proposals could be shelved.

That said, oil sands companies are working hard to bring costs under control through a series of initiatives to improve labour and transportation efficiency, find alternatives to natural gas, and address engineering design in cold climates. While a drop in oil prices might shelve a few projects, the general consensus is that a strong world economy will ensure a home for increased expansion. 'There continues to be a lot of optimism and progress on the oil sands side,' says Devries. 'It's pro-



Enbridge proposes new pipelines west...

... and south



Enbridge proposes new pipelines south

gressing according to plan.'

The major, immediate concern of the pipeline companies is obtaining shipping commitments. Over the last year, Enbridge and Terasen have been consulting with producers in Fort McMurray as well as refineries in Asia and California in an effort to firm up long-term agreements to use the pipelines. Slowly, interest has been coalescing. In December 2004, Enbridge announced that it expects to sign memorandums of understanding with several major Chinese refineries and that at least 75% of Gateway's 400,000 b/d capacity will be destined for markets in China, Japan and South Korea.

Yes, Minister

Assuming that producers duly come on board, the next major challenge is the regulatory process. Building a major pipeline in Canada not only involves proving to various provincial and federal governing bodies that the project has economic merit and is sound technologically, it must also meet stringent environmental requirements and obtain the blessing of communities that reside along the way.

Over the last few years, the cost and time of the regulatory process has grown so dramatically that it has attracted the ire of the Canadian Energy Pipeline Association (CEPA), the industry's lobby group. 'Environmental regulations are not terribly efficient or effective, and that has to change,' states CEPA President David MacInnis. 'In the North West Territories, there are roughly a dozen primary regulatory authorities to deal with. There is an effort to come together under one roof and coordinate, but it's not a perfect situation. When investors look at Canada, they need to see a regulatory system that ensures protection of the public and the environment, but allows business to do what it does to get energy to the market in a timely and safe manner.'

Enbridge has already taken significant preparatory steps with Gateway. 'We had a project team in place since 2001,' says Lacouvee. 'We've been out there very early. It really contributes to the overall planning to get input right upfront.' The company has focused special attention on the First Nations people, who occupy significant portions of the proposed right-of-way. 'There are over 130 aboriginal communities along the route. We continue to refine the corridor, but there are still 50 to 60 First Nation and Metis communities [who will be directly impacted].'

Gateway's engineering is another major challenge – the route passes through some of the most mountainous terrain in the world. Engineers have surveyed the route and done all preliminary engineering and cost analysis, and Enbridge is currently focusing its energies on trying to decide whether to terminate the line at Kitimat or Prince Rupert. 'Kitimat is the more costly route, and there's no deepwater port,' comments Lacouvee. 'Prince Rupert already has a deepwater port, but there's the environmental issue of running it along the Skeena River.' Building the pipeline in the remote region will also present complications. 'The main issue is the labour. It all depends on the number of projects that are running – Mackenzie, Alaska – we do not expect them to be running all at the same time, but there will still be competitive pressures on steel and labour.'

While the issues it faces are significant, timing for the Gateway project is still on target. 'The regulatory review process would start in 2005 and run for approximately two years, until the end of 2006,' says Lacouvee. 'Assuming a successful review, construction would begin in 2007 and proceed through 2008 and 2009.'

Thanks to a pre-existing right-of-way, TMX faces fewer hurdles, but it still expects a lengthy assessment and application process. If all goes well, procurement and construction will begin in 2007 for the first phase, and possibly the second phase. The first phase would enter into service in late 2008, with the second phase beginning to flow a year later. Shipper support will predicate the timing for the third phase.

In spite of the obstacles to success, pipeline producers are confident that the projects will proceed. 'My level of optimism is very high,' comments Enbridge's Lacouvee. 'In the last year or so, the concept is gaining acceptance in the market place. It's good for producers and it's good for the new markets.'

PANAFRICAN Energy

Invitation for Pre-qualification Dar es Salaam CNG for vehicles

The Government of Tanzania has placed into operation a Natural Gas network within Dar es Salaam. The gas is sourced from the Songo Songo gas field, operated by PanAfrican Energy Tanzania Ltd (PAT), a subsidiary of EastCoast Energy Corporation. PAT has placed the initial gas customers on gas supply. Phase 1 of the Natural Gas Ringmain network is a 10 inch HDPE low-pressure gas pipe, operated by PAT and owned jointly by Tanzania Petroleum Development Corporation (TPDC) and PAT.

PAT in joint venture with TPDC invites reputable companies to pre-qualify for the non-exclusive development of infrastructure and markets in Compressed Natural Gas for vehicles (CNG) in the Dar region. The companies or syndicates which pre-qualify will be either: existing distributors and retailers of petroleum products in Tanzania, with a capability to access world-class skills in CNG technology; or international operators of CNG businesses. A mandatory Pre-Bid meeting for those companies that pre-qualify is set for April 2005 (date to be advised).

Companies or Consortia wishing to be considered for pre-qualification should submit: The Company's access to capability and experience with CNG: Construction of CNG compressor stations; transportation of CNG to retail outlets, and assistance with conversion of vehicles to CNG; and submission of audited financial statements for the last 3 years.

Following the Pre-Bid meeting, Pre-qualified companies will be invited to submit within 60 days an outline development plan with details of the design, financing, construction and operation of one or more CNG compressor stations, and associated distribution. Retail outlet dispensers may be either part of the CNG project, or outsourced to existing fuel distributors.

Bidders will be selected based on capability, targets for build up of gas supply rates for CNG vehicles, and commercial terms. Interested companies may obtain more information from the address below; or email info@eastcoast-energy.com or phone +255-22-2121-938. Pre qualification submissions should be delivered in sealed envelopes clearly marked "PREQUALIFICATION FOR DAR ES SALAAM CNG PROJECT" by **31 March 2005** to the address below.

The CNG Project Manager
PanAfrican Energy Tanzania Ltd, Barclays House, 5th Floor
Ohio Street, PO Box 80139,Dar es Salaam

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14.00 *Registration*

14.15 Chairman's welcome and introduction
Chris Skrebowski, Editor, *Petroleum Review*

14.30 Market size trends – the facts and figures
Nigel Lang, Managing Director, Catalist

14.55 Strategies for third grades
Andrew Owens, Managing Director, Greenergy

15.20 Refreshment break

15.40 Forecourt marketing and design
Robert Onion, Director, Circle

16.05 Trends in environmental and legislative issues
Technical Team, Energy Institute

16.30 Questions and discussion
Led by Chris Skrebowski, Editor, *Petroleum Review*

17.00 End of seminar

For further information please contact Jacqueline Warner t: +44 (0) 20 7467 7116 or e: jwarner@energyinst.org.uk **or to register go to** www.forecourtshow.com

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Digital business – the next generation

Despite the dot.com debacle the oil industry seems to have kept faith with doing digital business – to a greater or lesser extent. We've moved beyond the hype, but the oil industry still lags behind many other sectors, such as chemicals, in terms of e-procurement, e-invoicing, e-requisition and even e-logistics. But new initiatives and partnerships are under way which address the complete supply chain, reports Brian Davis *in the first of a two-part analysis.*

After all the hype which heralded the launch of Trade-Ranger, Petrocosm, Trade Capture and so many other lip-smacking e-ventures, the digital business picture has gone very quiet over the last year or so. Some outfits talked about creating new business models, some identified useful niche activities, while others simply self-destructed.

ChevronTexaco's Petrocosm marketplace collapsed, although the procurement technology was taken in house. BP pulled its procurement activities out of Trade-Ranger, despite Lord Browne's express objective of handling 95% of procurement of indirect products and services using this marketplace.

Trade-Ranger itself has just been acquired by cc-hubwoo, while a Google search reveals precious little about oil and gas e-business initiatives post-2002. Has the oil industry simply flushed millions of dollars down the drain or is there still some drive and enthusiasm around the issue?

No longer the lone Trade-Ranger

John Wilson, CEO of Trade-Ranger, claims the marketplace expanded transaction volume of business to about $6bn in 2004, up from $4bn in 2003. Trade-Ranger currently handles about one million documents a year and is estimated to save between $5 and $10 per document transaction cost. Key customers include Shell, ConocoPhillips, Total, Dow Chemical, Total, Eni, Repsol, Solvay and Statoil. Most recently, BP decided to re-engage with Trade-Ranger.

However, the value of the transaction hub hasn't translated into substantial sales price reductions, admits Wilson. 'But it has allowed companies to manage their spend more smartly because it can be data mined. This drives better decision-making in the strategic supply chain and encourages vendor reduction using fewer "preferred" vendors.'

All well and good, but what about the $100mn or so pumped into Trade-Ranger by the original backers?

Under the terms of the new acquisition agreement, cc-hubwoo – a leading European provider of electronic procurement solutions and supplier network management – will acquire Trade-Ranger for between $18mn and $20mn in mid-May, with a cash consideration of $1.4mn and the balance in newly issued shares in cc-hubwoo.

On the face of it this doesn't seem a big return on investment. Wilson has no illusions: 'Trade-Ranger didn't look like a good "straight" equity investment. But the operational savings far outweigh the return on the initial investment.' One major customer estimates internal savings exceed $400mn from e-business, although not all these savings are directly attributable to Trade-Ranger. The big benefits come from better customer and supplier relationships. Better access to transactional and supplier data means they can negotiate mutually better deals, which can be rolled out globally with better contract compliance.

The scale of the new organisation will provide Trade-Ranger with a vastly increased presence in Europe and the US, rising from nine customers on the buy side to over 60. cc-hubwoo currently serves eight of the world's largest corporations (including Total, BASF, Alcatel, Bayer and Volkswagen), whose annual spend in indirect goods exceeds $100bn. On the supply side, Trade-Ranger will expand from 2,000 to over 14,000 suppliers with a common hub infrastructure.

Only three of the major Trade-Ranger customers use reverse auctions, the demand for which has plateaued according to Wilson. He believes reverse auctions are useful for procuring commodity-type products, where much of the engineering work can be done up-front. 'You need a huge amount of discipline to buy through reverse auctions, and many suppliers have been hugely reluctant to participate. There's also a trade-off between price reduction and the relationship maintained with a contractor.'

Last summer, Trade-Ranger introduced a new e-invoicing solution using a web-hosted application called TRUE invoice. Take-up varies among customers, but momentum is gathering. Ultimately, the enlarged hub will drive down costs for users, while increasing their trading opportunities and transactional knowledge. Trade-Ranger CEO Wilson however has other plans 'at the intersection between energy and IT' as cc-hubwoo has already absorbed four CEOs from earlier e-marketplace acquisitions. He doesn't fancy being the fifth!

Biggest spend management player

Ariba acquired Freemarkets last summer and now claims to be the largest player in oil and gas 'spend management', from e-sourcing to e-payment. Before the merger Ariba worked with ExxonMobil and ChevronTexaco on e-procurement, while Freemarkets worked with Shell, BP, ConocoPhillips, SABIC and, most recently, signed a deal with ADNOC in the Middle East.

Ariba is used to source both commodity and complex projects in both the upstream and downstream arenas, including downhole completion equipment, ROV services and drilling rigs. Atul Sahay, Director of oil and gas projects for Ariba EMEA, estimates the oil and gas sector is saving 14% on average through online bids. He also recognises that many suppliers are reluctant to participate in online bids, particularly where categories of products and services are difficult to scope. However, some oil companies insist on the necessity of such bids.

Sahay insists that the benefits of online bidding are not simply driving savings, but put more discipline and clarity in the sourcing practice upfront. 'If you maintain a very clear process, it can save time. Depending on the commodity sourced, companies can achieve 20–40% time saving using better spend management and online bids.'

Paul Hampton, Director of product marketing at Ariba EMEA, also points out the value of better visibility. This helps identify 'where and how' companies spend their money. 'Data collected from e-procurement helps define strategy and drive savings across the company,' he remarks.

'Maverick procurement practices which were commonplace less than a decade ago are currently being eliminated.'

Category-based sourcing and procurement savings are resulting in optimisation of the entire supply chain. Companies are now looking at the complete end-to-end process, which includes visibility of the spend, category management, supplier relationship, sourcing, e-RFX, contract management and compliance. Some independent oil companies are using Ariba as a source of valuable category and e-sourcing knowledge, with significant cost savings and impact on profitability.

At a time when oil prices are running at a record high, savings from e-sourcing may not seem to be a high priority. But Hampton believes oil companies are always looking at process optimisation and rationalisation. 'Delays in sourcing a completion for a platform can cost millions. So anything that ensures meeting the project schedule will save significant sums. E-sourcing and better spend management also facilitates improved collaboration, control, compliance and reduction of EPC project costs.'

According to Sahay: 'The category-based approach often starts downstream then moves upstream. Categories are grouped in common processes to help generate savings in products and services, with data easily mined online. Better category focus gives better visibility of the entire supply chain for strategic sourcing. This helps develop a clear strategy for negotiation and encourages internal and external compliance, with automatic invoicing and reconciliation.'

So, let's see how two major oil companies – Total and Occidental – are currently addressing their e-business initiatives.

Total commitment

Philippe Chalon, Chief Information Officer (CIO) at Total, says the group is committed to several e-business initiatives. E-procurement is based on the SAP enterprise resource planning (ERP) backbone, connected to the Trade-Ranger marketplace. 'E-procurement is mainly focused at the headquarters level, with pilots in some subsidiaries in France and Asia in the upstream arena,' he explains.

Chalon also emphasises the value of using e-business for contract compliance globally. 'For example, better compliance means the group avoids having to renegotiate IT purchases worldwide, with better synergy and return on investment (RoI) on an $800mn/y IT budget. Actually, e-business related technology and services only accounts for a fraction of the IT budget, and the main cost lies in interconnecting e-business with the existing IT infrastructure.'

'We are still are the early stage of e-business take-up, although 2005 is dedicated to increasing the number of transactions.' Rather than replacing existing purchasing services and personnel, Chalon sees the main benefit of e-procurement for improving negotiation. 'Having e-procurement allows us to negotiate with a rate decided by the HQ. Nothing is purchased today without negotiation.'

A second area of focus is e-transit for handling logistics and tracking distribution both upstream and downstream in real-time, with strong interactivity. Total has several tools for this purpose. 'The RoI is immediate with strong, easy and quick commitment from our subsidiaries,' remarks Chalon.

The third area of focus is e-invoicing, but it's still early days. 'E-procurement has to be fully successful before we bring in e-invoicing,' says Chalon, who is targeting 5% of invoices to go electronic by end-2005, 20% in 2006 and 70% by 2007.

Total uses Portum for most reverse auctions and occasionally works with Trade-Ranger. But surprisingly, Chalon believes: 'Reverse auctions may not always secure the best price but a reasonable price by putting people in competition. Sometimes you can get a better price using a top negotiator. And we still face resistance from contractors who insists you can't compare like with like.'

Chalon also believes that e-business activity will play a key role in operations upstream and downstream. The company is currently finishing deployment of a major ERP system, the backbone of e-business. The Template Europe project (with partners SAP, Accenture and Atos Origin) began in 2000 and covers all downstream activities, from refineries to marketing and customer facing processes.

The biggest hurdle for e-business implementation is the necessity for significant change management. 'You can't simply emulate systems you already have in place. That is a very costly approach,' says Chalon. 'You must reorganise the entire system. The key to success will be good integration of e-business with other systems to add value throughout the supply chain. I don't consider that we have global e-business yet. We have to take a pragmatic approach. It works better for some than others.'

Occidental goes its own way

Occidental was an early investor in Trade-Ranger but pulled out of the marketplace, while retaining a small percentage of equity, faced with the high complexity of doing transactions in its early days.

German Digoy, Director of SCM, Occidental Oil and Gas Corporation, has revisited the e-business implications for supply chain functions. 'Our first priority is spend analysis. In the past, we simply summarised spend by vendors but never drilled down to specific services. Today we use the digital world to drill down and look at services being provided.'

For example, the operator can review raw materials costs in a cementing job, transportation, equipment rental and other costs, and break each element down using better category management to factor jobs against specific performance categories. This approach has been used for the past year to measure asset performance at Elk Hills in the US, and most recently on the OPL Permian Basin in West Texas

Digitalisation has had several effects. A direct, electronic invoice process replaces manual invoice checking, checks pricing automatically and identifies invoice errors. Occidental uses Digital Oilfield, Canada, for handling digital invoices using a standardised digital format, registered with about 2,000 vendors. 'This service means we don't have to deal with multiple vendors and formats for invoicing,' says Digoy.

On the contracting side, Occidental has gained better performance data for strategic sourcing, and benefits from better knowledge of manpower, movements and vendor performance. As a result, significant savings have been made on contract price. 'We are moving from a purely price contract to a price/performance contract,' comments Digoy. Digitalisation is estimated to be responsible for savings of 2–5%, achieved mostly by improving contracting practices rather than manpower reduction.

Occidental uses Oracle's i-procurement for electronic requisition, purchase orders, inventory management, and as an i-suppliers' interface programme for procurement of commodities and point of sale material, but not well-field services. The group uses Procuri for reverse auctions in its chemicals business, and plans to pilot some upstream-related reverse auctions from mid-2005.

The group recently selected a new e-logistics provider – switching from Danfoss to Eagle International – which has an interface with their Oracle ERP system, so products shipped can be tracked globally.

'Having decentralised all IT functions only a few years ago, we are now co-ordinating supply chain management efforts better, with significant change management and IT support,' says Digoy.

Occidental also has digital oilfield initiatives, using visualisation centres in Houston, Qatar and Ecuador. This and other digital oilfield initiatives will be discussed in more detail in part two of this report next month.

Safety first when reorganising

Mark Scanlon, EI Technical Manager–Safety, reviews the safety risks associated with organisational change and outlines some resources designed to help industry better manage such change.

Captain control room

The pace of change for most organisations seems greater than ever, with no sign of let-up. This is inevitable in a world of pressures on businesses. For those involved, organisational change can be threatening and highly stressful, but for many it can also be an exciting, even exhilarating, opportunity to shape and improve working lives.

This applies as much to safety management as to any other aspect of business. Organisational change can be a chance to make big improvements. For example, it can allow a clarification of personal responsibilities at all levels and help empower people – give them greater means to identify and tackle safety, health and environmental (SHE) issues that affect them – or just help rejuvenate the SHE programme.

But there are risks too. For example, organisational changes were among the root causes in the Longford incident,[1] which resulted in two fatalities and caused major business interruption in Australia, and the fire at Hickson and Welch in Yorkshire (see **Box 1**).

The pressure and emotion that surround organisational change inevitably influences the way that decisions are made and, as the pace of change continues, many organisations have cut staff so far that they now appear to be beyond lean.

What are the concerns?

Over the past few years, organisational change has been top of HSE inspector requests for support from the HSE Hazardous Installations Directorate Human Factors and Safety Management Team. Inspectors were picking up concerns from employees and safety representatives about changes, often involving de-manning and/or relocation of functions, and they were often uncomfortable about them. In addition, inspectors found the topic difficult to regulate positively, because they lacked benchmarks against which they could assess companies' management of change process.

The same lack of benchmarks also created difficulties for the companies themselves, as there were no tried-and-tested approaches to these risk assessments, or even clear ideas about what risks they should be looking for. While some companies made a good effort to assess the risks – for example, by using detailed procedures in which forms were completed and approved by senior managers – such risk assessments were basically *ad hoc*. Add to this the difficulty that any of us have with being objective under pressure, and you have a recipe for some unsound decisions.

To illustrate HSE concerns, a case study involving poor management of organisational change by a company that is generally considered to be a high performer in safety is summarised in **Box 2**. In other cases, the impact of changes was more indirect and subtle, resulting in gradual accumulations of maintenance backlogs, operators carrying out new roles but without the necessary training or with unhelpful changes in management priority. Key lessons learned from case studies are given in **Box 3**. In addition, some self-assessment questions that can help determine whether there are

Box 1: Case study – Hickson and Welch (Castleford, Yorkshire)

In 1992, fires at Hickson and Welch resulted in five fatalities during the cleaning of a vessel containing potentially unstable sludge. Because of a recent company reorganisation, the cleaning task had been organised by inexperienced team leaders reporting to an overworked area manager.

The Health and Safety Executive (HSE) incident report[2] stated: 'Companies should assess… the workload and other implications of restructuring… to ensure that key personnel have adequate resources, including time and cover, to discharge their responsibilities.'

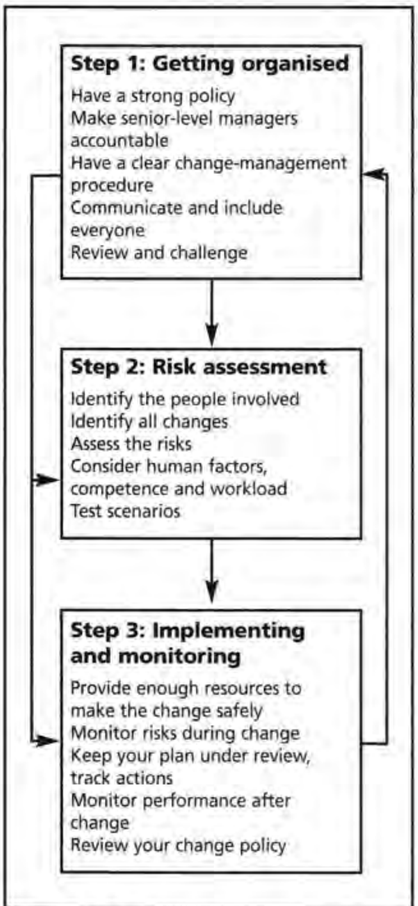

Figure.1: Summary of process for management of organisational change set out in CHIS7

problems arising from organisational change are given in **Box 4**.

Coherent resources

Clearly, these issues pointed to a need to develop coherent resources for managing safety in organisational changes.

The resources are:

- CRR348/2001 methodology[3]
- CHIS7[4]
- Staffing arrangements user guide[5]

They were written primarily for businesses with 'major hazards', which includes many onshore and offshore petroleum installations. These have the potential for high-consequence incidents and need to make a continuing demonstration of safe operation under the Control of major accident hazards regulations (COMAH) 1999[6] or similar regulatory frameworks.

Using the resources provides a means to consider safety implications when planning and carrying out organisational changes and to have a structured and effective process for ensuring that staffing arrangements are adequate for abnormal or emergency situations, as well as for steady state operations.

Box 2: Demanning case study

This concerned a simple demanning at a large site. Employee disquiet was loudest at one particular plant where, to enable a reduction in control room staff, a new 'crash' emergency shut-down (ESD) procedure was introduced that would bring the process to a sudden safe state. This new procedure was quite possible to do, but operators were all well aware that the cost in lost catalyst alone would be over £1.5mn on each occasion. Most were hesitant, at best, to take on that responsibility. As prompt ESD could no longer be relied upon under these circumstances, HSE prohibited demanning.

Box 3: Key lessons learned from organisational change case studies

❑ Human factors, particularly human reliability, need to be understood and tackled with as much rigour as engineering approaches to improving safety. For example, simply instructing people to do something does not mean that it will happen.

❑ In commercial enterprises, managers take calculated business risks to remain competitive. However, those managing major hazards must be particularly diligent in preventing major accidents.

❑ At times of change, almost no-one directly involved can truly be objective. Therefore, an independent individual should be involved in reviewing, or better still chairing, risk assessments – especially when discussing key safety-critical or safety-related functions.

Box 4: Self-assessment questions to determine whether there are problems arising from organisational change

❑ Are there enough people to carry out everyday work, and respond to any unusual or emergency situations?

❑ When employees' jobs are changed, do they get proper training in the new jobs?

❑ Are there enough people available to supervise all of the contractors working on site?

❑ Does management explain the need for change and consult or involve employees in the change process?

❑ Do systems that worked before the change still work as well as they did afterwards (for example, supervision or permit-to-work systems)?

These self-assessment questions are drawn from IP Human factors briefing notes resource pack, No. 3 Organisational change. *See Energy Institute website* **www.energyinst.org.uk/humanfactors.bn**

CRR348/2001 methodology

HSE commissioned Entec to develop a methodology for assessing staffing arrangements in process operations, in particular, control rooms. This is published as HSE *Assessing the safety of staffing arrangements for process operations in the chemical and allied industries* ('CRR348/2001 methodology')[3]. Industry was formally consulted during its development through a workshop.

The CRR348/2001 methodology is based on making a 'physical assessment' of performance in a range of scenarios and a 'ladder assessment' of management and cultural attributes underlying the control of operations. Using the CRR348/2001 methodology should allow companies to identify areas of unacceptable risk and the necessary improvements to reach acceptable levels with issues such as communication facilities, operator workload, management of operating procedures, etc. The improvements could include changing staff numbers or supervisory arrangements, but could also be brought about by improving hardware or software for detection, alarm or trip systems.

The CRR348/2001 methodology has proved very successful, and its uptake spread quickly across the petroleum, petrochemical and chemical industries. However, because its scope was limited, and because it suits some circumstances more than others, it was not *the* answer to organisational changes – there was need for broader guidance.

CHIS7

HSE therefore developed the concise, Internet-only publication *Organisational change and major accident hazards* ('CHIS7')[4]. This captures ideas from the CRR348/2001 methodology and lessons from pitfalls observed in inspections, such as lack of understanding of human factors, bias, marginalisation of safety in change management etc. This resulted in a three-

Box 5: Staffing arrangements toolbox

❑ The staffing arrangements toolbox provides those in the petroleum and allied major hazard industries with the resources necessary to better determine staffing arrangements in control rooms and similar locations. The toolbox brings together guidance, research, case studies and useful links. It comprises:

❑ The Staffing arrangements user guide

❑ The blank staffing assessment forms and checklist (as downloadable Word documents) that form Annexes D and F of the Staffing arrangements user guide

❑ A web link to the CRR348/2001 methodology report

❑ Courtesy of HSE, the blank physical assessment decision trees and ladders (as downloadable Word documents) from the CRR348/2001 methodology report

❑ Two case studies from the series of *IP Human factors safety information bulletins* that concern reviews of staffing arrangements in the context of broader organisational changes

❑ The IP Human factors briefing note on *Organisational change*

❑ A web link to further references on organisational change and staffing arrangements

❑ A web link to CHIS7

❑ A web link to HSE Research Report (RR292) *Different types of supervision and the impact on safety in the chemical and allied industries*

See Energy Institute website **www.energyinst.org.uk/humanfactors/staffing**

Box 6: Case study – Associated Octel (Ellesmere Port, Cheshire)

Associated Octel recognised that proposed major organisational changes to the staffing of its chlorine plant could jeopardise safety if not adequately assessed. The company applied the CRR348/2001 methodology to flush out areas of concern and develop pragmatic solutions. The approach enhanced a team culture and allowed operators to contribute to the development of their working environment. It also allowed management to determine what could be managed by changes to operational practices, or improved process control systems, and also to identify what changes were 'a change too far'.

For further information, see IP Human factors safety information bulletins, No. 3 Assessing staffing requirements for hazardous situations. *See Energy Institute website* **www/energyinst.org.uk/humanfactors/sib**

step safety management process that forms the core of CHIS7 (see **Figure 1**).

The guidance focuses on organisational change at operational and site level, but is also relevant to changes at corporate level, which, in turn, can have a significant impact on safety at operational level.

HSE trialled and refined CHIS7 by using it as *de facto* guidance in inspections for almost two years, and the processes described there were put into practice by many petroleum, petrochemical and chemical businesses. The guidance was also modified such that it placed less emphasis on one-off big changes, but more on permanent arrangements for management of continuous change. Industry was formally consulted on it through the Chemical and Downstream Oil Industries Forum and the Oil Industry Advisory Committee.

Staffing arrangements user guide

In response to feedback solicited by the Energy Institute requesting clearer guidance on using the CRR348/2001 methodology, the Energy Institute Human Factors Working Group, using Technical Partner funding and HSE co-funding, commissioned Entec to develop the Staffing arrangements user guide. This does not duplicate the CRR348/2001 methodology report but sets out a best practice approach to it. As a result, the two documents should be read alongside each other. In addition, the Staffing arrangements user guide includes supplementary guidance on how best to apply the CRR348/2001 methodology to automated plant and/or equipment.

Following consultation with the petroleum and allied major hazard industries, the Staffing arrangements user guide was published by the Energy Institute as IP *Safe staffing arrangements – user guide for CRR348/2001 methodology: Practical application of Entec/HSE process operations staffing assessment methodology and its extension to automated plant and/or equipment.*[5] Single users can download it from the Staffing arrangements toolbox (see **Box 5**).

What next?

Companies that have used the resources in their organisational changes are not leading to the kinds of unsafe conditions described earlier in this article. Some have been particularly successful (see **Box 6**).

Even if your organisation is not currently undergoing change, it soon could be! So it is not too early to have a look at CHIS7 in the first instance and start to design your own process. Those considering organisational changes should talk them through with their usual HSE contact.

References

1 Hopkins, A, *Lessons from Longford: The Esso gas plant explosion*, CCH Australia Ltd, Sydney, 2000, ISBN 1 86468 422 4.

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3 *Assessing the safety of staffing arrangements for process operations in the chemical and allied industries*, HSE Books, CRR 348/2001, 2001, ISBN 0 7176 2044 1. See HSE website **www.hse.gov.uk/research/crr_pdf/2001/crr01348.pdf**

4 *Organisational change and major accident hazards*, HSE, CHIS 7, 2003. See HSE website **www.hse.gov.uk/pubns/chis7.pdf**

5 *Safe staffing arrangements – user guide for CRR348/2001 methodology: Practical application of Entec/HSE process operations staffing assessment methodology and its extension to automated plant and/or equipment*, Energy Institute, 2004, ISBN 0 85293 411 4. See EI website **www.energyinst.org.uk/humanfactors/staffing**

6 *Control of major accident hazards regulations 1999,* HMSO, SI1999/743.

Find out more

To assist the industry in better understanding the safety implications of organisational change and staffing arrangements, the Energy Institute Human Factors Working Group is convening a seminar entitled 'Workload, organisational change and stress – practical application of human factors tools to major hazard operations' on Tuesday 26 April (in London). This will feature presenters from industry, HSE and consultancies, and will be used to launch the Staffing arrangements user guide.

For further information, contact Arabella Dick, t: +44 (0)20 7467 7106, e: **arabella@energyinst.org.uk** or see the Events calendar on the EI website at **www.energyinst.org.uk**

LETTER TO THE EDITOR

Dear Sir,

Dr Mamdouh G Salameh stated in his article 'Saudi proven oil reserves-how realistic?', *Petroleum Review,* February 2005, that Saudi Aramco's former Vice-President Sadad Al-Hussayni had insisted in articles appearing in the *Oil and Gas Journal* in the summer of 2004 that Saudi proven oil reserves amounted to only 130bn barrels.

I found that the actual article* by Sadad al-Husseini appeared in the 17 May 2004 issue of the *Oil and Gas Journal,* in which he stated that the 130bn barrels was the figure for the 'remaining proven *developed* reserves' and that there was a further 130bn barrels of 'discovered *undeveloped* reserves'. The rest of the article makes it quite clear that the reserve base upon which future production estimates are being made is 260bn barrels which, according to the author, represent approximately 25% of the world's proven reserves.

George Leckie
Industry Consultant

* *Al-Husseini, Sadad. 'Rebutting the Critics: Saudi Arabia's oil reserves, production practices ensure its cornerstone role in future oil supply',* Oil and Gas Journal, *17 May 2004, pp16–20.*

A response by Sadad Al-Hussayni will appear in April *Petroleum Review.*

Enhanced recovery from North Sea giants

The 25th anniversary of the start of production from Statfjørd – the largest oil and gas field in the Norwegian North Sea – provides a reminder of the importance of improving recovery from older fields. Statoil now aims to recover 70% of reserves from Statfjørd, a major improvement on the 48% that was originally expected. Improved recovery has also been achieved from Brent and Forties, the largest UK fields, reports Jeff Crook.

Statfjørd B – the 25th anniversary of the start of production from Statfjørd provides a reminder of the importance of improving recovery from older fields
Photo: Statoil

The Statfjørd field came into production on 24 November 1979 and has so far yielded oil and gas worth NKr1,045bn, according to operator Statoil. 'This development has exceeded all our expectations and has helped to shape Statoil,' comments Chief Executive Helge Lund. 'That's not only because of its big revenue stream, but also because of technological advances which have laid the basis for a further commitment off Norway and internationally.'

Statoil reports that 4bn barrels of oil and 70bn cm of natural gas have been recovered from Statfjørd so far, with additional output from the East and North satellites. When the field came onstream in 1979 the experts thought it would be possible to recover about 48% of the stock tank oil originally in place. The recovery factor currently stands at 63%, and the target is to reach as much as 70% – a very high proportion, even in a global context.

The field has been developed by three major platforms – Statfjørd A, B and C – and is currently flowing about 140,000 b/d of oil, compared with the record of 850,204 daily barrels set on 16 January 1987. Through the proposed Statfjørd late life project, Statoil is working to extend production by changing the drainage strategy in order to recover the gas still in the reservoir. Some of this gas may be exported to the UK via the Brent field facilities, from October 2007 – provided the late-life project is sanctioned.

Boosting Brent output

Brent is one of the two largest fields in the UK sector, along with Forties. Brent operator, Shell, originally estimated that it would recover 2mn barrels of stabilised oil (equivalent to 263mn tonnes of crude) from the field, together with 584mn barrels of natural gas liquids and 4.3tn cf (122bn cm) of sales gas.

Brent has been producing oil since 1976, when Brent Bravo – the first of its four platforms – came into production. Peak production was in February 1984 at 504,000 b/d of oil and 26.6mn cm/d of wet gas. The field was still producing 13% of Britain's oil and 10% of the country's gas in 1993 when a decision was made to go ahead with a £1.3bn re-development.

The project, which was undertaken from 1994–1997, involved the upgrading of the platforms to extend field life to 2010, and modifying the processing facilities to boost gas production. It was claimed to be the 'largest offshore field depressurisation ever attempted', according to Shell, whose aim was to recover an additional 1.5tn cf (42.5bn cm) of gas. The life of the platforms may be further extended to 2025.

Depressurisation has enabled high levels of gas production to continue, although oil production has been in steep decline. Following the onset of depressurisation, gas production increased to peak at 32mn cm/d of wet gas in March 2001, according to Shell.

A fuller production picture is provided by DTI annual figures, which show that while Brent's oil production has declined from around 20mn tonnes (400,000 b/d) in 1985, to 1.1mn tonnes (22,000 b/d) in 2003, gas production declined quite slowly over the same period. It has fallen from 8.4bn cm in 1985, to 5.6bn cm in 2003. Total oil production to the end of 2003 was around 317mn tonnes (2.3bn barrels), whilst total gas production was 180bn cm.

The level of Brent production has been boosted by new and emerging technologies such as multi-lateral and side-track wells, as well as thru-tubing operations. Reservoir management has been aided by a sophisticated simulation model of the entire reservoir, with 80,000 reservoir grid block models. One further innovation was the use of high capacity (1,250 HP) electrical submersible pumps (ESPs) to back produce water from the reservoir in order to replenish the gas cap (see *Petroleum Review*, February 2005). This latter scheme received the Energy Institute Technology Award for 2004 (see *Petroleum Review*, January 2005).

Focus on Forties

Forties has, meanwhile, yielded more than 2.5bn barrels of oil since start-up in 1975. Production peaked at about 550,000 b/d by the end of the 1970s, but had dropped by 90% when Apache bought the field from BP in April 2003 as part of a package of North Sea and Gulf of Mexico assets acquired for $1.3bn.

Forties production was running at 45,000 b/d at the time of the acquisition, with net proved reserves of 147.6mn barrels. Apache has since raised output with the aid of new infill wells based on BP information, achieving 58,000 b/d in 3Q2004.

BP passed over information for 19 possible future well locations when it sold the field. Apache then analysed these opportunities with the aid of three different 3D seismic surveys. The time lapse between these surveys allowed the company to use 4D analysis techniques to help select the optimum well positions. Having studied the information, Apache now plans to drill 30 additional wells.

The field is being subject to further upgrades, including the installation of a gas ring main at a cost of $30mn. This is expected to cut Forties' greenhouse gas emissions by about 46%, by reducing flaring and diesel fuel burning, whilst also achieving cost savings of $1mn per month.

As a result of drilling new wells, production had risen to 60,000 b/d by summer 2004. The oil is exported by the Forties pipeline system, which remains in its previous ownership and continues to transport around 1mn b/d from other North Sea fields.