Petroleum review

DECEMBER 2003

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover: *Petroleum Review* looks at how tanker operators are dealing with the vagaries of the marketplace, including an accelerated deadline for the elimination of single-hull tankers from the world fleet. **See p12.**

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ROUNDUP From the Editor

Russia – riddles, mysteries and enigmas*

The rapid recovery in Russian oil production from its nadir in 1996, when production fell to 6.1mn b/d, is a well documented success story. Current Russian production is now at, or close to, 8.5mn b/d. Analysts confidently expect this rapid expansion to continue, with figures of 10–10.5mn b/d pencilled in for 2010 and up to 12mn b/d by 2012 (see p4/5).

However, the recent arrest and imprisonment awaiting trial on fraud and tax evasion charges of Mikhail Khodorkovsky – at that time head of the newly formed YukosSibneft – caused a wave of concern to sweep through the oil and financial communities (see p8).

Widely ignored, but possibly significant, was the announcement by the Russian Deputy Prime Minister Victor Khristenko that once Russia had reached 9mn b/d in the 2006–2008 period it would then cap production at this level (see p5). This raises many questions – will it really take till 2006–2008 to reach 9mn b/d and, if so, are present flows exaggerated? Does Russia really plan to cap flows and how will it do so given the companies are predominantly privately owned?

Assuming for the moment that Khristenko's words were more than just sabre rattling, do they link in with the recent moves against Khodorkovsky and Yukos?

At the moment there are almost as many explanations as analysts:

- It is purely about applying the law and offers no precedents about future actions.
- Putin is moving against the oligarchs one by one. Having started with the ones with media interests, he is now moving onto the oil oligarchs.
- It isn't Putin at all but the 'Grey Cardinals', his KGB associates now promoted to power in the government and flexing their muscles.
- It is only about Khodorkovsky because he broke the 'deal' under which the oligarchs apparently agreed not to move into politics.
- It's all about the December elections and will be resolved after the ruling party is re-elected.
- It's all about Putin's second term and, once he's re-elected in March, all will be resolved.
- It's all about the traditional anti-semitism of the security forces.
- The prosecutor's office is acting completely independently, with no political pressure.
- It's about Putin's cronies getting rich in the way that Yeltsin's cronies did.
- It's all about stopping ExxonMobil or ChevronTexaco buying shares in YukosSibneft.
- It's all about the state keeping control of the oil industry.

Most of these suggestions are difficult to prove or disprove and there may be elements of several of them. What we do know is that Mikhail Khodorkovsky is currently languishing in gaol, charged with fraud and tax evasion. He has resigned his Chairmanship of YukosSibneft in favour of Simon Kukes, previously Chairman of TNK. Around 40% of YukosSibneft shares have been frozen by the Russian state. Confusingly there is also a story from the *Sunday Times* that these shares were made over to Jakob Rothschild before they were frozen by the state.

We also know that Putin has publicly committed himself to re-establishing the power of the state and to improving relations with all of states of the near abroad – Kazakhstan, Ukraine, Baltic republics etc.

The Russian state has much in common with Opec in terms of a heavy dependence on oil revenues and oil taxation. Victor Khristenko may even have been hinting they have an interest in conserving resources. In contrast, the Russian oil companies are keen to maximise returns by maximising production. Their interest being in minimal central control and the ability to export freely. Exports are currently constrained by the state's control of the pipeline monopoly Transneft, which is why the companies are keen to build their own export pipelines.

A major shareholding by an ExxonMobil or a ChevronTexaco would make it difficult for the Russian Government to control the oil industry. How the case plays out, and how freely shares in Russian oil companies can be traded will tell us whether the Russian state is consolidating power in the old way or whether the country is moving to a true market economy. Much is riding on the outcome.

Chris Skrebowski

*Winston Churchill – 'I cannot forecast to you the action of Russia. It is a riddle wrapped in a mystery inside an enigma'

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

e-world

OptiMet II is the latest generation of the Met Office's web-based meteorological and oceanographic information delivery system for offshore industry customers. It offers all the features of previous web packages, including ten-day site-specific wind and wave forecast tables and graphs, short-range forecasts for UK waters, enhanced graphical products, aviation forecasts, tropical storm warnings, satellite images, synoptic charts and sea temperature charts, plus several significant enhancements designed to deliver increased value and flexibility to the user. For more information on the services of the Met Office, visit **www.metoffice.com**

The International Petroleum Exchange of London (IPE), one of Europe's leading energy futures and options exchanges, has announced a deal with FutureSource to serve as the new technology provider for IPE EnergyLive™, the IPE's web-based, real-time data delivery product. The new version of IPE EnergyLive™ is reported to enable customers to gain access to additional functionality that will provide significant enhancements without an increase in subscription fees. Comprehensive charting and weather maps have been added to the existing real-time IPE prices, along with Dow Jones Newswires Energy News. IPE EnergyLive™ is available at **www.theipe.com/data/live.asp**

Emerson Process Management recently unveiled its new PlantWeb website – **www.plantweb.com** – that is claimed to 'bring together a wealth of information to help manufacturers achieve more than 2% improvement in efficiency of existing operations and save more than 30% on projects'. The site includes real customer cases and examples about the quantified business results that customers have experienced by utilising Emerson's PlantWeb® digital plant architecture in installations around the world, and across all industries.

The UK Government recently unveiled a new online database designed to stimulate more effective and, ultimately, increased recovery of hydrocarbons from the UKCS by improving access to the considerable R&D expertise available in the UK. Visitors to **www.oilresearch.info** can search by keyword for expertise and facilities to meet their particular requirements. Details are held for over 250 university departments and research and technology organisations (RTOs). Entries include contact points for more detailed enquiries and researchers can submit updated information online.

In Brief

UK

Talisman Energy has made a further oil *discovery in the central North Sea, adjacent to the Buchan field and the 2002 J1 discovery. The 21/1a-20 well flowed at 7,100 b/d of oil, plus 7.6mn cf/d of gas. Initial estimates suggest that the discovery contains 10–40mn barrels of oil-in-place. This is in addition to the 40–70mn barrels of oil-in-place already established on J1.*

Burlington Resources has secured an *exploration and production licence in the East Irish Sea on seaward blocks 113/21 and 113/22.*

North America

ChevronTexaco is to acquire additional *50% working interest and assume operatorship of the Blind Faith discovery from BP Exploration & Production. Blind Faith is located in Gulf of Mexico Mississippi Canyon block 696.*

In a lease sale planned in December *2003, the US Bureau of Land Management is expected to auction rights to drill for oil and gas on more than 6,800 hectares (17,000 acres), mostly in the Book Cliffs region of eastern Utah – an area that a 1999 review under the Clinton administration had determined could warrant wilderness protection.*

Unocal has taken Apache's 13% *working interest in the Unocal-operated Ship Shoal 208 field in the Gulf of Mexico and an undisclosed amount of cash in exchange for Unocal's majority interest in the Lake Pagie field in Terrebone Parish.*

Unocal has made a major hydrocarbon *discovery on the deepwater St Malo prospect in Walker Ridge block 678 in the Gulf of Mexico.*

Amerada Hess has announced a new *deepwater oil discovery at the Tubular Bells prospect in Mississippi Canyon block 725.*

Middle East

Total, Petronas, Agip, Statoil and BP *are reported to have made rival bids for exploitation of phases 11 and 12 of the South Pars gas field.*

WesternGeco has signed an agreement *with the Kuwait Oil Company (KOC) for*

Sands of time run out faster for Statoil

An increase of almost 30% in oil production during the month of September 2002 was achieved on the Gullfaks B platform, according to a report from the Norwegian Petroleum Directorate (NPD), writes *Brian Warshaw*. Almost entirely due to improvements in sand removal, it is claimed that enhanced safety, and reduced discharges into the sea, are additional benefits of the new system being employed by Statoil. The cost of the modifications for the 30 production wells on the platform has been financed by the improved output from just one well.

For a number of years Statoil, with the assistance of Det Norske Veritas, has been collecting and collating information about erosion problems created by entrained sand, and has evaluated various technical solutions based on the information. The result has been the development of a strategy that raises the amount of sand that can be accepted in the oil and gas. In 2001 Statoil undertook a pilot test on the Gullfaks A platform, during which the three wells recovered an additional 5,000 b/d of oil.

As fields mature, the tendency is for sand build-up to increase as a result of declining reservoir pressure and increased water production. This can result in a production well being shut down before the oil and gas are exhausted. The only method of reducing sand production hitherto has been to limit production to the maximum sand-free rate of one gramme per hour in the sand trap. Statoil's study showed that this could safely be increased to 10 grammes per hour, which it has designated as an acceptable sand rate (ASR). Production rates can be increased until the ASR is reached.

In practical terms Statoil has installed an additional sand monitor to each well, and applied continuous analysis to the impact of erosion. This has led to better evaluation of wear on choke valves and other equipment, while improved design to some other items of equipment exposed to sand has reduced the effect of erosion.

The concept is to be extended to Gullfaks A and C, and Statoil is confident that it can improve the recovery rate based on oil reserves from 59% to 62%. Pilot trials have also been started on the Statfjord B field.

According to NPD, the greater quantities of produced sand will, after cleaning, be re-injected into the well along with the drill cuttings. They will therefore not compromise the more stringent discharge rules relating to environmentally hazardous substances, which come into effect at the end of 2005.

Nigerian discovery for ChevronTexaco

ChevronTexaco affiliate, Star Ultra Deep Petroleum, has made a significant oil discovery on its Nigeria deepwater oil prospecting licence (OPL) 249. The wildcat Nsiko-1 well, which was drilled to a total depth of 13,968 ft and in 5,674 ft of water, discovered a substantial amount of net hydrocarbon pay in multiple zones. One zone was tested in the well and flowed at 6,500 b/d under restricted flow conditions. Appraisal drilling on the Nsiko discovery is planned for 1H2004.

In addition, the Aparo 3 appraisal well confirmed the extension of the Aparo oil field onto OPL 249. The well, drilled in 4,270 ft of water to a total depth of 12,000 ft, encountered a substantial amount of net oil sand. The results from the well indicate that the OPL 249 Aparo, OPL 213 Aparo, and oil mining lease (OML) 118 Bonga SW discoveries share a common structure and thus should lead to a joint oil development project.

Iran to hold first tender for LNG projects

Iran is expected to soon hold its first ever tender for the construction of LNG installations. The country is understood to currently be in discussions with BP and Shell regarding a number of LNG projects. The tender is understood to involve gas desalination facilities, liquidation equipment, loading facilities and two LNG production lines each with a capacity of 4.8mn t/y.

Iran is also reported to be considering bringing onstream its Zagros field in March 2004, with production expected to reach to 100,000 b/d within two years. The South Zagros Oil and Gas Development Company is understood to be implementing several gas projects on the field, with daily production targeted at 180mn cm.

TNK-BP could double reserves

BP has said that under the rules of the US Securities & Exchange Commission (SEC), which take account only of volumes that can be produced during the life of current oilfield licences, its new TNK-BP Russian joint venture would have estimated proven oil reserves of 4.1bn barrels. The estimate would more than double to 9.4bn barrels based on criteria set by the Society of Petroleum Engineers (SPE), which take account of production that can be recovered economically over full field life. Proposals are currently before the Russian Parliament to extend oilfield licences.

These large volumes, together with more than 21bn barrels of oil and gas resources additionally discovered by the joint venture, were disclosed by BP Chief Executive Lord Browne in a recent presentation to the financial community in London on the company's $6.8bn Russian investment.

Browne said that oil production from TNK-BP's operations averaged 1.2mn b/d over the first half of this year, 10% up on 2002. Some 51% of the output was exported as crude to internationally-priced markets and 11% as refined products. An additional 9% went to CIS countries at higher-than-domestic prices. The company is seeking to boost exports further.

The average price received per barrel for the half year was $21.80, with lifting costs of $2.50. Production is expected to rise by 12–14% over the year as a whole and a further 7% in 2004. A 'steady-state' rise of some 5%/y is envisaged thereafter – although this will be subject to change as business plans develop and reserves are added.

Browne said its half-share of TNK-BP would make up some 15% of BP's total production, a percentage unlikely to change over the next five years. It would represent some 11% of BP's proven oil and gas reserves and 3% of capital employed.

Ohanet onstream – on budget and on schedule

BHP Billiton and Sonatrach have brought onstream the jointly operated Ohanet wet gas project in southern Algeria, on schedule and within the original $1bn budget. The new processing facility will treat some 710mn cf/d of gas and produce up to 30,000 b/d of condensate and 26,000 b/d LPG, together with a stream of dry pipeline sales quality gas for Sonatrach.

A total of 28 new wells have been drilled and completed, and 15 existing wells recompleted to develop the four reservoirs forming the development. A further four wells will be drilled after three to four years of production.

Revival in UK onshore exploration

Black Rock is to farm out 5% interests in the UK onshore oil exploration licences PEDL 098, 099 and 113. The licences cover most of the Isle of Wight and the area inland from Portsmouth. The interests will be earned by the contribution by Hereward Ventures of a 10% share of future costs, which will include an appraisal well to test a logged oil accumulation that is expected to be drilled on the Sandhills-2 prospect on PEDL 113 on the Isle of Wight.

The Sandhills structure is thought to contain some 49mn barrels of probable reserves, with 76mn barrels probable plus possible.

Interest in onshore exploration in the UK has undergone a revival recently with the success of the Avington-2 well, near Winchester in Hampshire. This found 100mn barrels of oil in place, of which between 10–15% is deemed recoverable. Pentex is operator.

Additional discovery nearby Chinguetti

Woodside Petroleum (35%) has made an oil and gas discovery at the Tiof prospect offshore Mauritania. The Chinguetti-4-6 exploration well, which lies 25 km north of the original Chinguetti oil discovery, intersected a gross gas column of around 48 metres and an oil column of at least 38 metres. Partners in the Chinguetti block are Agip (35%), Hardman Resources (21.6%), Fusion (6%) and Roc Oil (2.4%).

The Chinguetti discovery is currently being appraised and the partners are working towards making a final investment decision on a development of the field in March 2004. Chinguetti is expected to cost around $400mn to develop and is forecast to produce 75,000 b/d in its first two years.

Depending on its size, Tiof may be tied back into facilities at Chinguetti or developed as a standalone project.

In Brief

a comprehensive Q-Reservoir(a) project in Kuwait. The project, which includes Q-Land(a) seismic acquisition, processing and interpretation, began early November and is expected to be complete by spring 2004.

Gazprom is reportedly planning to *submit a preliminary bid in December in a tender to equip the 15th and 16th phases of the South Pars field in Iran. The two phases involve service work, including drilling and platform construction, the construction of a pipeline shore, and construction of a gas processing plant. South Pars reserves are put at 12.6tn cm of gas. The 15th and 16th phases of field development are expected to supply over 18bn cm/y of gas to the Iranian market, to export about 29mn barrels of condensate and 1mn tonnes of liquefied associated gas, and also produce over 1mn tonnes of ethane.*

Dolphin Energy is reported to have *signed long-term agreements to supply gas from Qatar's North field over 25 years to the Abu Dhabi Water and Electricity Authority (Adwea) and the Union Water and Electricity Company. The field is due onstream in 2006. Reserves are put at 10tn cf.*

Russia & Central Asia

Gazprom is reportedly planning to *produce 542bn cm of gas in 2004 – some 10.3bn cm more than production in 2003.*

The tender for the Talakan field in *eastern Siberia is expected in 2Q2004. Russian definition ABC reserves are put at 770mn barrels of oil and 44bn cm of gas.*

Gazprom Head of Marketing, Alexander *Mikheev, is reported to have forecast that independent Russian gas producers will generate 63.6bn cm of gas in 2003, up from 53bn cm in 2002. Some 37bn cm of this is expected to be produced by oil companies.*

It has been reported that the Russian *Government is threatening to strip Yukos of some of its exploration licences, citing failure or partial failure to fulfil licence obligations.*

By 2010, Russian oil production is likely *to reach 10.4mn b/d and, with the requisite level of investment, could reach 12mn b/d, according to a recent report by Wood Mackenzie. Ian Woollen,*

In Brief

Senior Analyst, comments: 'Events in the Russian oil industry in 2003 have been ever more remarkable. Oil production in Russia continues to increase at a rate of 11% per annum, on target to average 8.5mn b/d in 2003.'

***ChevronTexaco has sold Texaco North** Buzachi, which holds a 65% stake in the North Buzachi oil and gas field in northwest Kazakhstan, to CNPC International) for an undisclosed sum. Field reserves are put at 1.5bn barrels of oil in place.*

***The Russian Government is under-** stood to have stated that it is not planning to increase production above 9mn b/d, which the government expects to be achieved by 2006–2008.*

Asia-Pacific

***Talisman Energy's Hoa Mai-1X explo-** ration well in block 46-Cai Nuoc offshore Vietnam has tested at 34,000mn cf/d of gas. Hoa Mai is estimated to hold between 70bn and 100bn cf of recoverable gas reserves and may be developed as a tie-back to the recently installed PM-3 CAA facilities.*

***CNOOC is understood to be planning** to build a 360-km offshore pipeline to provide gas from the Panyu gas field in the South China Sea to southern China's Guangdong Province and Macau next year. Panyu's recoverable gas reserves are put at 1.5tn cf. Due onstream in 2005, the pipeline is expected to transport 100mn cf/d of gas by 2006.*

***OMV began full production from the** Sawan gas field in southern Pakistan on 22 October 2003. Output of 9mn cm/d more than triples the Austrian company's current production in Pakistan from 5,000 to 18,000 boe/d, reportedly making it the largest international gas operator in the country. OMV will now be responsible for meeting 18% of Pakistan's gas demand. Some 60% of this demand will be met by production from Sawan, 30% from the Miano field and 10% from Kadanwari.*

Latin America

***A Petrobras-led consortium has won** the bid for the contracting of services for the development of the Cuervito block in Mexico's Burgos Basin.*

NEWS Upstream

New and improved UKOOA unveiled

A 'new-style' UK Offshore Operators' Association (UKOOA) was launched during its 30th Anniversary celebrations in Aberdeen on 6 November 2003. The reorganisation, which has been in development over the last two years, has seen a new membership representative structure put in place and senior management recruited to strengthen the UKOOA team. 'Branded "Raising the Game" the programme has been designed to provide the UK offshore oil and gas sector with a representative body that is appropriate for taking the industry forward as it moves through the mature lifecycles of the UKCS', stated the Association.

According to Steve Harris, UKOOA's Acting DG: 'UKOOA's new structure will improve focus on industry priorities, speed up policy decisions and provide flexibility to respond to issues as they arise... Crucially, there are now clearly defined access points into the organisation where members, regulators, legislators and other key stakeholders can go for industry positions on policy and dialogue.'

Gasification project planned for Irkutsk region

TNK-BP, together with the Irkutsk Region Administration, is holding a tender for drafting the investment feasibility study under the Irkutsk Region gasification project. Up to 4bn cm of gas will be supplied to the Irkutsk Region under the first stage of the project, to be increased up to 10bn cm in the future.

The project will start with development of the Kovykta gas condensate field and construction of the pipeline system to Sayansk and Angarsk. In the long run, small gas fields to the south of the Irkutsk Region will be developed and incorporated into the Irkutsk Region gas system; the gas system will also be expanded in the west.

At the final stage of the region's gasification programme it is proposed to incorporate the Verkhnechonsk and Yaraktinsk fields and to create a 'single gas system' in Eastern Siberia.

Oil price above Opec target range

August 2003 saw UK oil prices sustained at levels above the Opec target price range following its decision to cut production quotas to 24.5mn b/d from 1 November, according to the latest Royal Bank of Scotland *Oil & Gas Index*. Oil production, at 1,907,113 b/d, fell on the month (–3%) although it was marginally higher on the year (0.5%). However, higher oil prices in August ($29.5/b) resulted in revenues being up on both the month and year, at £53mn. Gas production was up (3.9%) on the month and year (3.3%), at 9,279mn cf/d.

'UK exploration levels are currently extremely low, emphasising the importance of the oil industry and government working closely to maximise incentives and maintain stability,' said Tony Wood, Senior Economist at the Royal Bank of Scotland Group. 'Low OECD stocks, Middle East tensions and more positive news from the US economy present significant risks of higher prices throughout this winter, albeit that the potential still exists for markets to become over-supplied in the spring,' he continued.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Aug	1,895,886	8,918	28.40
Sep	2,127,594	9,176	28.40
Oct	2,301,341	11,145	27.60
Nov	2,001,329	11,772	24.20
Dec	2,353,028	12,542	28.30
Jan 2003	2,274,870	12,857	31.20
Feb	2,215,831	13,570	32.20
Mar	2,251,714	12,392	29.90
Apr	2,092,765	10,840	27.50
May	1,948,620	9,636	25.60
Jun	1,940,265	9,910	27.30
Jul	1,957,888	8,931	28.50
Aug	1,907,113	9,279	29.50

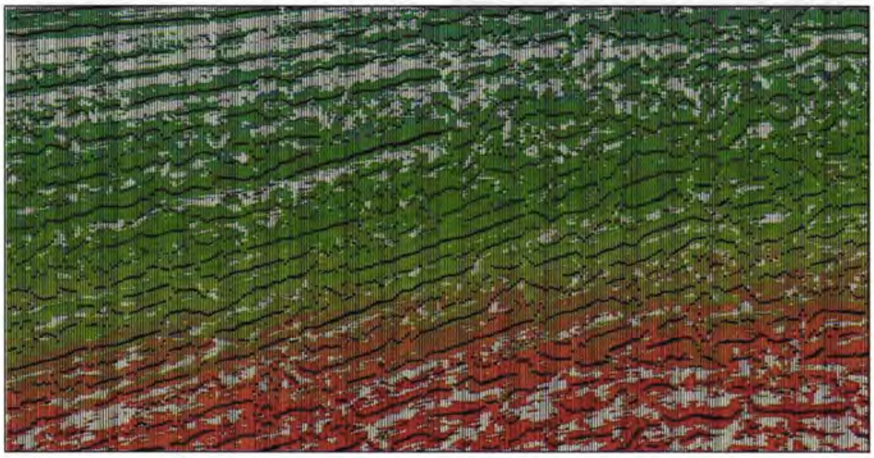
Source: The Royal Bank of Scotland Oil and Gas Index

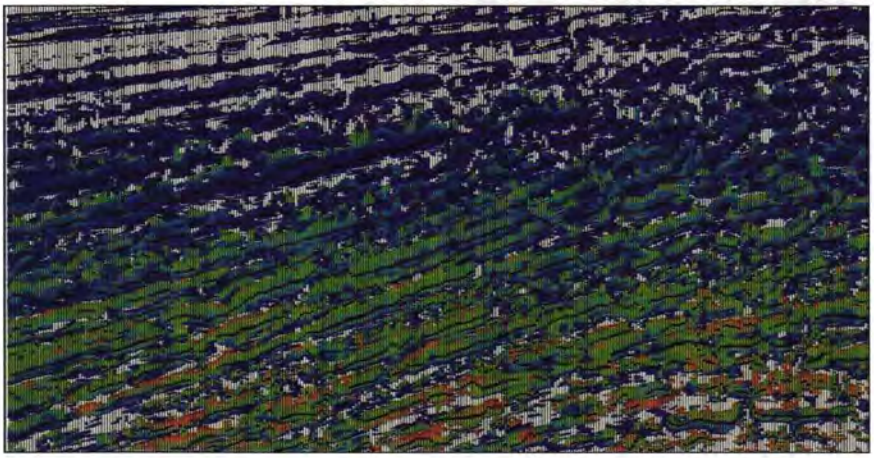
North Sea oil and gas production

Speaking a common seismic language

CGG recently launched HDPIC, a new approach to picking seismic velocities that reconciles geologists and geophysicists by delivering geologically meaningful seismic attributes. HPDIC is a new feature of A+ processing, CGG's fully anistropic seismic data processing service, which exploits the Earth's anisotropy to deliver a sharper, more focused image of the reservoir.

Velocities are critical for both geologists and geophysicists but do not necessarily mean the same thing to each discipline. Until now, anisotropy, which must be handled properly for velocities to become geologically meaningful, has remained unresolved by prestack migration schemes. According to CGG, with its HDPIC technology, the effects of anisotropy are effectively separated from velocity estimation so that the resulting fields make more geological sense.





CGG's newly launched HDPIC routine enables geologists and geophysicists to work with the same velocities for the first time in 40 years. The approach generates RMS velocities (top figure) and corresponding anisotropy η (bottom figure) for every location from automatic picking of seismic events (the picked 'skeleton' is shown as black lines).

For the geologists, it is useful to see that the velocity field goes across the layering roughly following the water bottom, while the η field closely follows the layering skeleton and ensures flat gathers for the geophysicist.

In Brief

ChevronTexaco is reportedly planning *to invest \$100mn/y in Venezuela's Boscan oil field in the Maracaibo area in order to maintain the current production level of 115,000 b/d. ChevronTexaco also plans to produce first gas from the block by 2009, and to develop it in a joint venture with ConocoPhillips.*

Repsol YPF has been awarded a services *contract for the development and exploitation of the Reynosa-Monterray block in the Burgos Basin in northern Mexico. Repsol YPF plans to invest some \$170mn in the next three years, with an estimated budget of \$42mn for 2004. It is planned to increase gas production from the current 400,000 cm/d to 2mn cm/d by 2007.*

Africa

BP and RWE Dea are understood to *have made a significant gas discovery – Ruby 2 – in the West Med Deep concession in the Mediterranean Sea offshore Egypt. The find tested at 30,000 cm/hour.*

Apache has reported that its Egyptian *Qasr-2X appraisal well has confirmed the Qasr-1X discovery announced in July. Reserves potential is now put in the range of 1–3tn cf of gas and 20–70mn barrels of condensate.*

Sudan is reportedly planning to *increase oil production to 312,000 b/d from 270,000 b/d in 2004. Plans have also been unveiled to increase exports to 31.2mn barrels.*

ExxonMobil and Sonangol have made *two deepwater oil discoveries, Kakocha and Tchihumba, the fifteenth and sixteenth oil finds on Angola's block 15. Kakocha-1 was drilled in 1,030 metres of water and tested at 4,500 b/d of oil. Tchihumba-1, drilled in 1,190 metres of water, tested at 7,470 b/d.*

First Calgary Petroleums and state- *owned Sonatrach are to to jointly develop the Menzel Ledjmet East (MLE) gas and condensate field in block 405b of Algeria's Berkine Basin at a cost of \$700mn. First production is expected in 2007. Proved, probable and possible reserves are put at more than 5.7tn cf of gas.*

Some 20 companies are understood to *have made bids for nine offshore blocks in Sao Tome & Principe's first licensing round.*

In Brief

UK

BP has reported a 3Q2003 net profit, *adjusted for special items, of $2.87bn (£1.7bn), up from $2.3bn in the previous year, helped by rising oil and natural gas prices.*

Shell has reported strong third quarter *results for 2003 with net income of $2.7bn, similar to 2002 – bringing net income for the year to date to a record $10.8bn, a rise of 52%.*

Europe

Total has posted a 3Q2003 net income *of 1.71bn, an increase of 7% compared to 3Q2002.*

Repsol YPF reported net income of *1,608mn for the first nine months of 2003.*

The Italian government has sold 2.1bn *worth of Enel's shares to reduce its national debt.*

Candover Partners, 3i Group PLC and *JPMorgan Partners have signed a preliminary agreement to acquire most of the upstream oil, gas and petrochemicals business from ABB for between $925mn and $975mn. The mainly downstream business ABB Lummus Global is not included in the acquisition.*

Norsk Hydro has posted a 3Q2003 net *income of NKr2,397mn.*

Statoil has posted an income of *NKr12.2bn before financial and other items, tax and minority interests for 3Q2003.*

North America

ConocoPhillips has posted a 3Q2003 *net income of $1,306mn, compared with a net loss of $116mn for the same quarter in 2002. ExxonMobil reported a 3Q2003 net income of $3,650mn, an increase of $1,010mn from the third quarter of 2002, while ChevronTexaco reported net income of $1.975bn, compared with a net loss of $904mn in the year-ago period. Unocal posted net earnings in the third quarter of $152mn, Marathon $281mn, Apache $276mn, Amerada Hess $146mn and Petro-Canada $311mn.*

Shell is planning to expand its growing *US position in LNG with the develop-*

World's largest GTL plant unveiled

Qatar Petroleum and Shell have signed a Heads of Agreement (HoA) for the construction of what is claimed will be the world's largest gas-to-liquids (GTL) plant in Ras Laffan, Qatar. The project includes the development of a block within Qatar's vast North field gas reserves, producing 1.6bn cf/d of gas.

Shell plans to invest around $5bn to develop upstream gas and liquids facilities and an onshore GTL plant that will produce 140,000 b/d of GTL products (primarily naphtha and transport fuels, with a smaller quantity of normal paraffins and lubricant base oils) as well as significant quantities of associated condensate and LPG. The project will be developed in two phases, with the first phase operational between 2008 and 2009, producing around 70,000 b/d of GTL products. The second phase will be completed less than two years later.

Shell already operates the world's first commercial-scale GTL plant, in Bintulu, Malaysia, which currently produces 12,500 b/d of transport fuels and speciality products.

ChevronTexaco plans Mexican LNG terminal

ChevronTexaco is planning to construct a $650mn offshore LNG receiving and regasification terminal off the coast of Baja California, Mexico. The company is working with Mexican authorities to secure permit approvals for the project, which is slated for start-up in 4Q2007.

The proposed terminal will be constructed using a gravity based structure (GBS), a freestanding concrete structure, along with mechanical facilities capable of offloading, storage and regasifying LNG. It will be designed to process 1,400mn cf/d of gas, with initial processing of approximately 700mn cf/d.

John Gass, President of ChevronTexaco Global Gas, said: 'Growing demand for natural gas in North America is widely projected to outstrip current supply capabilities. We believe ChevronTexaco's proposed Baja California offshore LNG project will help fuel the development of a sustainable, future energy plan for Mexico and the United States and play an important part in meeting this demand.' The recent National Petroleum Council study, commissioned by US Secretary of Energy Spencer Abraham, projected LNG imports into North America would grow from 1.4bn cf/d in 2003 to 8.5bn cf/d by 2015.

Gass continued: 'The Baja California proposal will allow the company to commercialise natural gas resources, such as the world-class Gorgon gas field in Australia, by providing access to meet the growing demand for natural gas in North America.' In August 2003 the company announced that it had signed a Memorandum of Understanding (MoU) with the Gorgon Joint Venture, an offshore natural gas project in Australia of which ChevronTexaco is a partner, for the supply of approximately 2mn t/y of LNG for delivery to North America over a 20-year period.

ChevronTexaco's global gas strategy incorporates large gas field developments such as the greater Gorgon area in Australia and Plataforma Deltana in Venezuela; a proposed LNG project in Angola and the recently announced Brass LNG project in Nigeria; gas-to-liquids projects through its Sasol Chevron joint venture; and proposed offshore regasification projects, including Baja California in Mexico and the Gulf of Mexico in the US. Additional LNG terminal projects are also under consideration for potential installation in California.

Nigerian LNG destined for US

NNPC (Nigerian National Petroleum Corporation), ConocoPhillips, Eni and ChevronTexaco have signed a Heads of Agreement to conduct the front-end engineering and design (FEED) work for a new LNG facility to be constructed in Nigeria's central Niger Delta.

The onshore LNG facility will be built at the Brass oil terminal operated by Nigerian Agip Oil Company (NAOC). The FEED will be for two trains, each nominally sized at 5mn t/y. Natural gas supplies for the facility will come from substantial gas reserves within oil and gas fields already operated by existing NAOC and ChevronTexaco joint ventures.

The FEED studies are expected to complete in 2004, and the facility is targeted to be operational at the end of 2008. The primary market for the first Brass train will be the US. Average daily sales volumes from the project are estimated to be around 700mn cf of natural gas.

Yukos assets frozen, future uncertain

Standard & Poor's Ratings Services has placed its 'BB' long-term corporate credit rating on Russian oil company Yukos on CreditWatch with negative implications. In a related action, Standard & Poor's has revised the CreditWatch implications on its 'B+' long-term corporate credit rating on Sibneft, which is 92% owned by Yukos, to developing from positive.'The CreditWatch actions reflect our concern that the recent freezing of the 44% stake in Yukos indirectly owned by the company's CEO, Mikhail Khodorkovsky and several other people raises the risks for creditors by threatening the ownership rights and governance processes of both Yukos and Sibneft,' said Standard & Poor's Moscow-based analyst Elena Anankina.

The share-freezing adds to the uncertainty caused by the ongoing legal and tax allegations against Yukos and its core shareholders, as well as by the recent arrest of Khodorkovsky. It also raises general concerns about the poor protection of ownership rights in the Russian Federation, where the political and legal environment remains opaque and unpredictable, and where enforcement of legislation and regulations appears increasingly selective.

'Resolution of the CreditWatch status of both Yukos and Sibneft will require an assessment of the risks to governance, finance, and operations caused by the General Prosecutor's investigation and tactics. We will focus our analysis in particular on the extent of interference with Yukos' and Sibneft's management, and on the companies' ability to control their financial and other assets', added Anankina. Upon completion of the merger, the rating on Sibneft will be based on that on Yukos (to be renamed YukosSibneft) and on the standing of Sibneft's creditors relative to those of the parent company.

Hat-trick of LNG newbuilds for BG

BG Group has entered into an agreement with Samsung Heavy Industries of Korea to purchase three newbuild LNG ships. The 145,000 cm capacity ships are expected to be delivered in 2H2006. BG has also secured options with Samsung for up to a further four newbuild ships for delivery in 2007. In total, the cost of the three ships and the options will be approximately $460mn.

BG currently owns two LNG ships (*Methane Arctic* and *Methane Polar*) which are on long-term charters in the Atlantic Ocean and Mediterranean Sea. Methane Services Ltd (MSL), a wholly owned subsidiary of BG Group, also charters four ships from Golar LNG (*Hilli, Gimi, Khannur* and *Freeze*), all of which are contracted to either long-term or short-term sub-charters. MSL also has commitments to take delivery of two new LNG ships (*Methane Kari Elin* and *Methane Princess*) under long-term charter in mid-2004.

Algerian LNG destined for UK market

BP and Sonatrach are to form a joint venture that will supply LNG from Algeria and elsewhere to the UK market, with scope to expand the arrangement to the US and other markets. The two companies have also successfully bid for the long-term capacity rights in the Isle of Grain import regasification facility, which is being developed on the Medway River, 20 miles east of London, and is owned and operated by National Grid Transco (NGT). The capacity rights will enable the two companies to source and then supply around 500mn cf/d of LNG into the UK market from 2005 – representing approximately 5% of UK demand.

Japan National Oil to be liquidated

Japan National Oil is understood to be selling some ¥30bn ($277mn) of shares in state-owned Japan Petroleum Exploration as part of the government's plan to liquidate Japan National Oil. It is reported to be the first initial public offering by a Japanese state-owned company for six years. Japan National Oil once controlled more than 300 companies as part of a 36-year plan to gain overseas reserves for a country that imports 99.7% of its oil. The government has closed at least 227 of the companies and plans to shut more after most failed to find oil, leaving the parent company saddled with debt.

Japan National Oil is also planning to sell an oil and gas company to be formed out of the merger of Inpex Corporation, Japan Oil Development and Sakhalin Oil Gas Development. The government is also understood to be planning the sale of stakes in other companies, such as Electric Power Development, which sells electricity to Japanese utilities, as part of its efforts to cut back public debt.

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ment of a new import terminal in the Gulf of Mexico by its wholly owned subsidiary Gulf Landing. The new terminal is expected to be operational in 2008/2009, with the capacity to deliver 1bn cf/d of gas into the US interstate pipeline network.

Middle East

The US Army Corps of Engineering is *reported to have said it is to delay awarding two contracts to repair Iraqi oil infrastructure in both the south and north of the country at a cost of $2bn.*

Russia & Central Asia

The Yukos Board of Directors has *appointed Simon Kukes as Chief Executive.*

Gazprom Deputy CEO Alexander *Ryazanov has stated that the company is to buy 6bn cm of gas from Turkmenistan in 2004, which will be used to fulfil a contract between Ukraine and Turkmenistan.*

Transneft has increased the capacity of *the Baltic Pipeline System to 600,000 b/d. A final 240,000 b/d increase will come onstream in June 2004.*

The World Bank's private sector arm is *reported to have approved up to $310mn in loans for multibillion-dollar projects to bring oil from the Caspian Sea to world markets. The International Finance Corporation is understood to have committed $250mn dollars for a pipeline being built by BP and others to carry crude from Azerbaijan to Turkey through neighbouring Georgia. A further $60mn will help finance development of the Azeri-Chirag-Gunashli (ACG) deepwater oil field of Azerbaijan.*

Sibneft has posted net income of *$1.378bn for 1H2003 in US GAAP audited consolidated financial results.*

Lukoil is to sell to Gazprom up to *0.75bn cm of gas in 2005 and in 2006 .*

Asia-Pacific

Total and Hindustan Petroleum, India's *third largest refiner, are to build a 60,000 tonne capacity LPG import and underground storage terminal in Visakhapatnam in the state of Andhra Pradesh.*

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UK

A new, flexible, online credit card *offering up to 1.6% cash back and a balance transfer rate of 5.9% for the life of the balance (14.9% typical APR variable) has been launched in the UK by Texaco and Accucard. By visiting* **www.texacocard.co.uk** *cardholders can tailor their account to suit their individual needs.*

The IPE (International Petroleum *Exchange) established a new monthly volume record as 3,354,804 lots were traded on the Exchange during October 2003. This surpassed the previous record set in January 2003 by approximately 2.5%. Representing an underlying value of $83.3bn, the volume in October was equivalent to 3bn barrels of crude oil.*

Powergen has acquired Midlands *Energy. The subsidiary of the Germany utility group E.On paid Midland's US owners Aquila and FirstEnergy £1.46mn to secure the deal. The sale forms part of E.On's European expansion plans, to which it has already allocated some £7bn (10bn).*

Europe

The Danish gas market is due to open *up to full competition on 1 January 2004, offering all gas customers in Denmark a free choice of gas supplier. DONG Transmission has published the Network Code rules and tariffs for the transmission of gas over its grid at* **www.dongtransmission.dk**

Shell and Volkswagen have unveiled *a joint programme for the development of new engine and fuel technologies. The programme will build on Volkswagen's optimised drive systems and Shell's GTL fuel technology to further reduce consumption and emissions. The companies believe that synthetic, liquid fuels form 'the ideal transition from hydrocarbon to hydrogen'. The next step in synthetic fuels development will be the improving of the carbon dioxide balance. According to Shell and VW 'one promising route' is the gasification of biomass to feed into the gas-to-liquids production process. This 'SunFuel', as it has been called by VW, is reported to 'offer the prospect of carbon dioxide neutral mobility in addition to the proven advantages of Shell GTL'.*

Automotive trials back Shell GTL fuel

Shell reports that independent tests on a fleet of Volkswagon Golfs in Berlin have shown its gas-to-liquids (GTL) transport fuel, which is compatible with modern diesel engines, 'significantly reduces tailpipe emissions'. The main test results are reported to have shown:

- A more than 26% reduction in particulate emissions compared to sulphur-free diesel in VW Golf TDIs equipped with advanced Euro 4 engines.
- A 6% reduction in nitrogen oxide emissions.
- A near 63% fall in hydrocarbon emissions due to improve combustion.
- A 91% reduction in carbon monoxides.
- A 4% fall in carbon dioxide emissions due to Shell GTL's higher hydrogen content.

Shell states that the 'tests prove that many Euro 3 engines with GTL fuel would meet the more stringent requirements of Euro 4 without the need for further modifications to the drivetrain. GTL fuel produces reduced emissions that are compatible to the direct use of compressed natural gas, but is cheaper over the product cycle and does not require the establishment of a new infrastructure.'

UK power supplies under pressure

Further to the news that UK power generators have warned of future blackouts, electricity sector chiefs would like the government to reinstate capacity payments as a means of ensuring future security of supply. However, with a relatively new Energy Minister, this is more about pressuring tactics than market realities, comments analyst Datamonitor.

Ian Russell, the Chief Executive of ScottishPower, is reported to have warned that a power supply crisis is a distinct possibility within the next few years. The combination of scheduled closures of older nuclear and coal-fired plants, together with the UK's current low renewable capacity means that blackouts could occur. Russell and other industry executives have stated that they are not prepared to invest in new plants while wholesale prices remain low.

ScottishPower and Powergen, two of the UK's largest electricity suppliers, are understood to favour a return to capacity payments, abolished with the introduction of NETA in 2001. Under the old pool system, capacity payments were made to generators in return for keeping less efficient plants operating. Currently the market has no equivalent mechanism and the reserve margin has fallen from the deemed safe level of 20% to as low as 2% on one occasion in the past year, says Datamonitor. National Grid Transco (NGT) has suggested that the margin could fall to as low as 7% this winter.

The capacity payments system, which was open to manipulation, did at least provide sufficient advance warning to generators to bring mothballed capacity back online. At present 4.6 GW of generation capacity in the UK is mothballed, with NGT estimating that 55% of this can be operational at short notice.

According to Datamonitor, it would take an exceptional combination of factors to bring about blackouts in the UK this winter. Although the longer-term situation will require careful planning, NGT is currently examining a range of options to ensure security of supply this winter. These include allowing plants to operate at above their maximum generating levels and offering large power consumers 'turn down' contracts to reduce consumption at times of peak demand.

Datamonitor believes Russell's comments are an attempt to pressurize the government and Ofgem, both thought to be opposed to capacity payments, into market intervention. Both should resist the industry's latest attempts at coercion, states the analyst.

Shell to roll out Diesel Extra across UK network

Shell has launched Shell Diesel Extra at more than 300 of its service stations in North, North West and North East England, replacing conventional diesel at these sites at no extra cost to the consumer. The new fuel includes 'a unique formulation' that is claimed to clean the engine, making it more responsive and efficient, leading to better engine performance and increased fuel economy as well as reduced emissions.

Shell Diesel Extra also has a higher cetane number than conventional diesel, aiding combustion and leading to the engine running more smoothly with less noise and reduced emissions, comments the company.

Shell plans to soon roll out the new diesel fuel across the rest of its 1,100-strong UK network.

Major growth in sales from UK forecourt C-stores

The average weekly sales in a company-managed forecourt in the UK have increased by 53% since 2000, according to IGD's latest research. The increase is being driven by improved store formats, expanded ranges and a general focus on convenience as forecourt retailers shift their focus from fuel sales to the shop.

IGD reports that grocery retailing on the forecourt has grown to over £3.6bn, a 14% increase in sales since 1999. It is worth 16.9% of convenience store sales and is delivering a like-for-like sales growth of +4%.

The average size of a forecourt store has increased by 29% in the last three years, ahead of the rest of the convenience sector, and there has been a lot of activity in format development. In order to improve their convenience offer, retailers are increasing the size of their stores by refits, extensions and rebuilds.

The breadth of range in forecourt stores is also reported to be expanding. Whilst product ranges are narrower and tend to focus on brand leaders and top sellers, to make the most of the small store space categories such as top-up groceries, alcohol and food-to-go are increasing their presence in the forecourt. Fresh fruit and vegetables have already increased their share of the sales mix from 0.5% in 1998 to 1.2% in 2002. The gradual liberalisation of attitudes to forecourt alcohol licensing laws has seen beers, wines and spirits increase their share of sales to 2.7% on average in 2002.

Forecourts have recognised the opportunity in providing more food-to-go products – for example, BP's Wild Bean Café is now the fifth largest coffee house in the UK with a 7% market share. Total has also developed a food-service offer at its Bonjour sites. Food-to-go ranges are developing from coffee and pre-packed sandwiches to a key category serving products such as freshly baked baguettes, salads and cappuccinos and IGD expects more growth in this area in the future.

Challenge posed by global warming

The immediate challenge posed by global warming to the petroleum industry – reducing carbon dioxide while maintaining low-regulated emissions – has to be combined with care that consumers can afford resulting new technologies and fuels, a Royal Institute for International Affairs' climate technology conference in London recently heard. Mark Gainsborough, Vice President (Fuels) for Shell International, said more needed to be done than just developing cleaner hydrocarbon fuels, more fuel-efficient and low-emission engine technology, plus renewable biofuels such as ethanol and vegetable oil esters, fuel cells and hydrogen systems, writes *Deirdre Mason.*

Gainsborough warned: 'Alternatives need to meet economic and social sustainability criteria as well as contributing to environmental objectives. We need to understand the challenge of consumer acceptance – you cannot leave that as an afterthought.'

He also said that that the petroleum and automobile industries could not go on relying on the 'end of pipe' clean-up technology that has worked reasonably well so far. What was needed now was a more comprehensive analysis of the problems. He said Shell believed that dieselisation offered a short-term opportunity for greenhouse-gas reduction that should be seized, and that internal combustion engine hybrids can deliver significant further benefits, particularly for petrol. Evolution from improved conventional gasoline and diesel through biodiesel and bioethanol blends to arrive at 100% renewable blends was another strategy envisaged by him. For the next 20 years, however, he saw dieselisation, hybridisation and the use of renewable blending components as having more impact than hydrogen.

Chris Mottershead, Climate Change Advisor for BP, said that his company had expected to take 10 years to meet international 2010 carbon dioxide emissions standards; but actually met it within three years and that the initial \$20mn outlay was more than balanced by the \$630mn brought in through emissions trading. 'Our long-term viability has to be in other ways than taking carbon out of the ground and throwing it into the atmosphere,' he told delegates.

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OMV has completed the acquisition of *140 service stations formerly held by the Austrian service station operator Avanti. The 40mn deal increases OMV's market share in Austria to 10%, and enables it to optimize the supply position of its refinery in Schwechat, as the new stations lie within the territory supplied by the refinery. OMV will continue to market in Austria under the strong Avanti brand and will pursue a clear dual-brand strategy there.*

North America

ExxonMobil is planning to launch sales *of its new proprietary racing oil – Mobil 1® Racing 0W-30 – to the US public in early spring 2004.*

Shell Aviation has marked its return as *a major player in the American general aviation market by launching a new credit card that can be used not only to pay for fuel and lubricants, but for a whole range of airport services including weather reports, route planning, landing and departure fees and catering. The card is welcomed at more 250 airports in the US and 750 Shell Aviation facilities in 90 countries.*

ExxonMobil has unveiled its new Mobil *1® Truck & SUV Formula synthetic motor oil in the US that is claimed to provide 'outstanding engine protection' for light trucks and SUVs (sports utility vehicles) 'in every kind of driving condition'. Designed for use in both gasoline and diesel engines, Mobil 1 Truck & SUV Formula 'uses special additives designed specifically to keep light truck and SUV engines cleaner than conventional motor oils by providing exceptional resistance to high-temperature varnish and low temperature sludge deposits that can dirty an engine and rob performance,' states the company.*

Valero Energy has selected CB&I, *through its Process and Technology Group, to design and build sulphur recovery/tail gas treating units at its refineries in Three Rivers, Texas, and Ardmore, Okla. The units will be designed to recover 99.9% of the sulphur from the feed waste gases at each of the facilities.*

ExxonMobil has introduced to the US *market Exxon Superflo™ High Mileage motor oil designed to protect engines with over 75,000 miles. The new formulation is designed to provide protection for critical engine parts in higher-mileage vehicles. The motor oil*

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is available in three conventional viscosities – 5W-30, 10W-30 and 10W-40.

Asia-Pacific

***BP is understood to have been given** the green light by the Chinese authorities to establish, jointly with PetroChina, 300 service stations in Guangdong Province. The oil company is also seeking permission to build a further 500 sites in Zhejiang Province. Earlier this year Shell and Sinopec were given clearance for 500 outlets in Jiangsu Province.*

***Shell has launched a new diesel fuel** in Australia that is claimed to 'dramatically reduce the smoke commonly emitted by commercial diesel vehicles'. Shell Aquadiesel is an emulsification of 85% diesel, 13% water and a 2% proprietary additive – the water in the diesel allows it to be combusted more completely and cleanly. The fuel is reported to reduce particulate matter by up to 60%, smog-creating oxides of nitrogen (NO_x) emissions by up to 15% and carbon monoxide (CO) emissions by up to 50%.*

***BP (40%) and Guangzhou Development** Industry Holding (GDIH) (60%) have signed a joint venture contract for the establishment of BP Guangzhou Development Oil Products Company to operate a world-class oil products terminal at Nansha in the Panyu district of China's Guangdong Province. The $86mn terminal will have a storage capacity of over 360,000 cm for chemicals, gasoil, gasoline and fuel oil products, and will be operational in 1Q2004.*

German power companies top customer service survey

Research from independent market analyst Datamonitor reveals that with a 96% customer service satisfaction rating, German major power users are the happiest in Europe. Not only are the country's suppliers jointly closest to delivering on major power users' expectations at home, they also have the greatest potential to meet customers' expectations in the other key European markets. 'This is an added deterrent for foreign players thinking of crossing the German border,' comments the analyst. 'Moreover, it is an encouraging finding for German players outside their domestic market, such as E.ON, EnBW and HEW operating in France, Italy and the Netherlands.'

Datamonitor also found that most European customers have similar requirements, preferring a hands-off, no frills approach to customer service, irrespective of the market. However, despite the simplicity of this request, very few suppliers are delivering on expectations.

French players fare well in meeting the expectations of Europe's least fussy customers, reports the company. Based on in-depth interviews with over 1,500 major power users across France, the UK, the Netherlands, Italy, Spain and Germany, Datamonitor established energy buyers' level of satisfaction with their power supplier's customer service. They communicated their expectations across 18 different service elements and rated their supplier's success in meeting them. From this, customer satisfaction scores were derived, whereby 100% represents complete fulfilment of expectations.

German utilities emerged as the joint best customer service providers, with power suppliers achieving a 96% satisfaction rate. French suppliers, including EDF, SNET and Energie Du Rhone were next, achieving a satisfaction rating of 95% in serving their market. The Netherlands and Spain compare most unfavourably at 85% and 80% respectively. However, given that French customers are the least demanding of the six European markets, French suppliers do not fare so well when their performance is mapped onto the higher expectations of customers in the other five countries. Only Dutch suppliers achieve a lower score when their performance is assessed against customer needs in other markets. Conversely, Spanish suppliers are subjected to the most demanding energy users and therefore, despite achieving 80% in their own market, they score as much as a satisfaction rating of 96% when French customer expectations, for example, are factored into the equation.

Nevertheless, Datamonitor found German suppliers prevail as having the best customer service overall, even when accounting for national variations in expectations. 'This is a positive result for players venturing outside their domestic market, especially when coupled with the finding that customers' highest expectations are for the same service dimensions, irrespective of the market in question. This fact increases the transferability of sales and marketing strategies', says the company.

UK Deliveries into Consumption (tonnes)

Products	†Sep 2002	†Sep 2003	†Jan–Sep 2002	†Jan–Sep 2003	% Change
Naphtha/LDF	186,236	191,499	988,326	1,693,133	71
ATF – Kerosene	1,014,736	922,561	7,701,994	7,672,054	0
Petrol	–	–	–	–	–
of which unleaded	1,554,828	1,639,714	14,627,702	14,070,752	–4
of which Super unleaded	53,452	70,125	425,545	613,036	44
ULSP (ultra low sulfur petrol)	1,501,376	1,569,589	14,202,157	13,457,716	–5
Lead Replacement Petrol (LRP)	31,584	13,437	424,045	160,002	–62
Burning Oil	302,927	283,280	2,714,197	2,701,522	0
Automotive Diesel	1,424,029	1,489,523	12,591,872	12,547,451	0
Gas/Diesel Oil	512,975	592,887	4,513,958	4,678,957	4
Fuel Oil	139,368	152,788	1,393,588	1,745,635	27
Lubricating Oil	62,796	69,397	616,344	629,721	2
Other Products	644,023	531,217	6,095,482	6,103,621	0
Total above	5,873,502	5,866,303	51,667,508	52,229,716	1
Refinery Consumption	407,421	277,445	3,731,228	3,335,679	–11
Total all products	6,280,923	6,163,748	55,398,736	55,565,395	0

† Revised with adjustments

All figures provided by the UK Department of Trade and Industry (DTI)

Choppy waters

Petroleum Review looks at how tanker operators are dealing with the vagaries of the marketplace, including an accelerated deadline for the elimination of single-hull tankers from the world fleet.

In a world so dependent on oil, it is perhaps surprising that so little public attention is paid to the tanker industry as it goes about its vital daily routine of carrying oil from producer to refiner. Only when things go wrong does the tanker industry become visible and, over the past year, operators have been having to face up to changes brought about as a result of two such incidents, namely *Erika* and *Prestige*.

The regulatory environment, which for so long was dominated by increasingly stringent requirements emanating out of the US following the *Exxon Valdez* incident in Alaska in 1989 and the subsequent Oil Pollution Act 1990 (OPA 90), has shifted to one driven primarily by European concerns. The actual outcomes are very similar but the schedule under which single-hull tankers are to be eliminated from the world fleet has been accelerated. This has made it difficult for tanker owners to plan and monitor their investments, especially during times of volatile income.

And 2003 was indeed a volatile year. The lengthy uncertainty generated by the run-up to the war against Iraq caused a major spike in market indicators across the size ranges that lasted from late 2002 well into 2Q2003. Again, after the summer market lull, tankers rode the coat-tails of a general bull run in the shipping business, although this was relatively short-lived.

Europe takes the lead

Europe's unilateral action against single-hull tankers took effect on 21 October 2003 and is already having a major impact on the tanker market. Effectively, all Category 1 tankers delivered in or before 1980 are now banned from EU and EEA (European Economic Area) waters and ports, and are also banned from flying the flags of those nations. Significantly, among the ten nations due to accede to the European Union next year are Cyprus and Malta, two states with extensive ship registers that include a large number of tankers. Owners of fleets registered in these countries will have to comply with the EU/EEA requirement on their accession to the EU – or, alternatively, move to non-EU flag states.

Category 1 tankers built in 1981 have another year, but all such ships will be outlawed from EU waters by 2005. Category 1 tankers are those of 20,000 dwt or more that are carrying crude oil, fuel oil, heavy diesel oil or lubricating oil as cargo, and tankers of 30,000 dwt or more with other types of oil, that do not comply with the requirements for new oil tankers as defined in Regulation 1(26) of Annex I of MARPOL 73/78.

Category 2 tankers are those that do comply with Regulation 1(26), while Category 3 tankers are smaller vessels of between 5,000 dwt and 20,000 dwt. For single-hull tankers of these Categories the phase-out schedule is a little more relaxed, beginning this year with ships built in 1975 or before. Newer ships will still be allowed to trade in Europe up until 2010. Those with double sides or double bottoms may be allowed to continue to trade until 2015 or 25 years of age, whichever is the earlier.

Unilateral action of this sort is anathema to an industry that is, by its very nature, international in scope. However, industry may not have to wait too long for the rest of the world to catch up, since it has been strongly hinted that the International Maritime Organisation (IMO) may well introduce parallel regulations at a meeting of the Marine Environment Protection Committee (MEPC) scheduled in October.

Speaking at the annual Tanker Operator Conference on the very day the new regulations came into force in Europe, Robert Somerville, President and Chief Executive Officer of the American Bureau of Shipping (ABS), predicted that the new regime will have a 'profound effect on the worldwide tanker fleet'. He also spoke of the chance that IMO would be 'bullied' into matching the requirements in international conventions.

Furthermore, the changes raise three specific challenges to the tanker industry, as well as to classification societies (such as ABS), shipyards and others who provide a service to tanker owners. Firstly, Somerville said, shipbroker Clarkson reports that 461 Category 1 tankers will have to be taken out of service by 2005 and some 700 Category 2 tankers – those with segregated ballast tanks but single hulls – will have to be retired by 2010.

Given the spate of new tanker construction and the placement of additional contracts recently, replacing the Category 1 tankers should not be a problem. However, Somerville said, it may only be through expansion of existing shipyard capacity in South Korea and China that the loss of the Category 2 tankers will be made up.

More than numbers

A less obvious risk involved in the phasing out of single-hull tankers relates to ongoing maintenance of those single-hull tankers that still have some years' trading in them. 'The imposition of an artificial age limit on existing vessels removes many of the incentives that currently exist for an owner to maintain his vessels to the highest standards,' Somerville explained. Such a situation would be exacerbated by the development of a two-tier market in which earnings for single-hull tankers are substantially less than those for double-hull ships.

The regulators believe that the prospect of criminal sanctions against a polluting ship, its crew and its owner will be enough to ensure that these single-hull ships are maintained properly. However, Somerville said, the ability of the owner to evade responsibility has been displayed in recent cases and punishment has fallen largely on the master and crew.

Another safety net put in place by the regulations is that those single-hull

ships that the EU provisions will allow to continue trading for some time yet will have to undergo inspections according to an expanded Condition Assessment Scheme (CAS). There are problems with this approach, too, not least in the need for additional manpower on the part of the classification societies that will be called upon to carry out much of the work.

The final issue raised by Somerville in his presentation was the development of appropriate survey and maintenance regimes for double-hull tankers. It has become apparent that double-hull ships suffer from very different ageing problems than those experienced with single-hull vessels. Surveys have found accelerated pitting in the cargo tank bottom plating, as a result largely of the warmer temperature of the cargo (the double hull acting as insulation against the cooling effects of seawater). The restricted size of the void space between the inner and outer hull makes it hard for inspectors to gain access in order to survey corrosion rates and the degree of coating breakdown. And there is the possibility of oil or – possibly worse – vapour seeping into the void spaces due to cracking, pitting or detail failure in the inner tank as the vessel ages.

These changes are taking place at a time when tanker operators, in common with those in many other sectors of the world merchant marine, are having to get to grips with the new International Ship and Port Facility Security (ISPS) Code, agreed by IMO in December 2002 to give an international counterpoint to the US's domestic Maritime Transportation Security Act (MTSA). In what is already a highly regulated industry, operators are not finding too much trouble or expense in meeting the Code's requirements, especially as it essentially mirrors safety-related measures in the International Safety Management (ISM) Code. Managers have already coped with this and understand the concept. However, it has added extra training requirements and calls for the appointment of both shipboard and shoreside security officers.

Other security-related provisions introduced by the US as part of its worldwide shield against terrorism have impacted more harshly on other transport sectors, most notably container shipping, and have had little effect on the tanker trades.

Market changes

While getting used to the new regulatory framework, tanker operators have also been getting on with the business they get paid for. It has been something of a strange year in the oil trades, however, beginning with the uncertainties over oil supply from the Middle East in the event of military action against Iraq. As in previous times of tension, all available tonnage was chartered at increasingly high rates to ensure that the supply of oil continued unabated. The impact on spot freight rates began to be felt as early as November 2002, rising to a peak between February and April 2003. During this time rates for all sizes of crude oil tanker were at levels comparable with the last spike in late 2000/early 2001. VLCC (very large crude carrier) rates on Middle East-Europe trades shot up from around W45* in October 2002 to peak around W120 by mid-January and again to over W125 in May.

After US President Bush declared hostilities effectively over in May, the freight market quickly fell back to more 'normal' levels. However, as the northern hemisphere summer progressed, it became increasingly evident that the oil supply pattern would be

changing. As Opec tried to work out how it would accommodate a return of Iraqi oil to the open market, it also had to keep an eye on Russian producers, who over the past year have been increasing output and switching Baltic loading points to enhance deliverability. Therefore, after dipping back to W45 in August this year, VLCC rates again picked up on the back of rising exports, peaking at over W130 in late September, but fell away quickly as Middle East Opec producers restrained output.

During the leaner times, VLCCs have moved out of the Middle East export trades and picked up cargoes from West Africa. A significant trade has developed in movements into Asia, and cargoes for discharge in China have provided useful long-haul employment. To some extent this emerging trade has helped to increase volatility in rates, since it removes larger tankers from the Middle East for weeks on end, allowing short-term tonnage tightness to occur. Another factor that has encouraged volatility during 2003 has been the comparatively low level of stocks in consuming countries, particularly in the US. This has been the case for crude oil as well as refined products, and spot freight rates for clean product tankers have been just as unstable.

Much of 2002 was appalling as far as freight rates for product tankers were concerned. However, as with the crude trades, rates began picking up from the fourth quarter and reached a peak in March of this year. After experiencing a decline once the tension in the Middle East began to ease, rates rose again in the third quarter, largely on the back of gasoline imports into the US.

Opinion seems divided on the outlook for the tanker market. Broker Simpson Spence & Young (SSY), for instance, stated in a recent report that growth in Chinese oil demand will continue to generate firmness not only for VLCCs trading out of the Middle East and West Africa but also Aframax markets within Asia and the regional product tanker trades. Such is the extent of this additional demand that it will help support global freight markets and soak up any additional tonnage arriving from the shipyards.

Drewry Shipping Consultants is more circumspect. In its *Annual Tanker Market Review and Forecast*, published in September, the analyst cautions that the growing orderbook threatens to put a lid on potential earnings at a time when economic growth outside of China is sluggish at best and when the new legislation on single-hull tankers and the continued war on terrorism are introducing a significant element of uncertainty.

Drewry notes that promising freight rates and comparatively low newbuilding prices – as well as the need for fleet replacement in light of the accelerated single-hull phase-out schedule – have encouraged a spate of new contracts, that has pushed up the orderbook to 28% of the existing fleet. Acknowledging that the freight market peaks of earlier this year are unsustainable, Drewry predicts that there will be some firmness into 2004 but that, further ahead, supply side factors will dampen earnings.

Special ships

The recovery in the chemical tanker sector has been steadier, if less spectacular, with growing optimism of a better year to come. The restructuring process that has already seen the long-haul sector dominated by just four operators has extended to the short-sea trades, with a number of new pooling agreements and takeovers announced this year.

The level of cooperation among the deepsea operators has, however, caused problems with competition authorities in the US and Europe. Investigations have been started into accusations that the major operators – Stolt Parcel Tankers, Odfjell Tankers, Jo Tankers and Tokyo Marine – were colluding to avoid competing on price. Stolt-Nielsen Transportation Group (SNTG), Stolt Parcel Tankers' parent company, offered to cooperate with US authorities but this nevertheless resulted in the replacement of a number of senior executives. Odfjell also came to agreement with US investigators, although in this case it has resulted in the imposition of a $42.5mn penalty, payable over five years, together with prison terms of four and three months for two senior executives. Investigations continue by both US and EU authorities and further action cannot be ruled out.

Growing LNG orderbook

If the chemical tanker sector was lively for the wrong reason, the most exciting sector of the tanker market this year has undoubtedly been LNG. Eight new ships were delivered during the first three quarters of the year – a sizeable number in a fleet of less than 150 – and another 10 ordered. The orderbook now stands at nearly 60 tankers, equivalent in capacity terms to almost half of the existing fleet.

A few of these new LNG tankers have been ordered without firm employment lined up, a novel development in a market where new buildings are normally only contracted with a 20- or 25-year employment contract already lined up. The LNG sector has now reached a size where spot cargoes are becoming available and where some of the bigger operators have more loading and discharge options available to them, so raising the need for a merchant fleet. Firm forecasts of a structural tightness in the US natural gas market also mean that there is a great deal of confidence in the future development of LNG imports into existing and planned terminals on a more market-related basis than is the case with other importers.

Once that happens, there will be an opportunity for a freight market for LNG tankers to develop, which could have an interesting impact on shipping costs for existing contracts.

** W=Worldscale – a rating system that allows charterers and owners to compare rates on different routes. Every year the Worldscale Committee publishes a comprehensive list of what W100 is in $/t for every conceivable journey around the world. W45=45% of the W100 value.*

E&P developments down under

Last month's *Petroleum Review* looked at recent E&P developments in the Asia-Pacific region where interest is increasingly focusing on exploiting gas. In Part 2, we review developments in Australasia.

Completion and tow out of the first wellhead platform for the Bayu-Undan project in Timor Sea
Photo: ConocoPhilips

As elsewhere in the Asia-Pacific region, gas exploration and production is a key driver for the Australasian oil and gas industry – in particular offshore the north and north-west coasts of Australia. However, international competition for investment in the oil and gas sector continues to intensify and only the most profitable projects are getting the go-ahead.

One of the biggest challenges for players in the Australasian arena is securing markets for the gas produced as the local domestic market is not large enough to support the ever growing number of projects waiting to be developed. A primary focus is the emerging LNG market in China, with the North West Shelf project securing a number of LNG supply contracts in recent months (see *Petroleum Review*, November 2003).

AUSTRALIA

Australian oil and condensate production currently only meets 75% of domestic demand, according to the Petroleum Division of the Department of Industry and Resources, and if no new discoveries are made, this figure is forecast to fall to 50% by 2007. Western Australia is expected to play a key role in helping Australia offset this decline in liquids self-sufficiency and provide additional security of supply, as a number of new developments are due onstream over the next few years.

Western Australia produced 334,000 b/d of liquids in 2002 – forecast to drop to 96,000 b/d by 2010 if no new fields are developed to replace consumption. However the Mutineer/Norfolk and Exeter fields in the Dampier sub-Basin are expected to add 88,000 b/d once onstream in 2005, building up to 100,000 b/d. Total production is forecast to be around 13.8mn barrels in 2005 and approximately 35mn barrels in 2006, based on currently estimated proven and probable reserves of 101mn barrels. Field life is put at seven years.

This will be followed by a further 75,000 b/d of production in 2006 from the Enfield/Laverda/Stybarrow fields in the Carnarvon sub-Basin. Reserves in Enfield/Laverda/Stybarrow are put at more than 300mn barrels of recoverable oil – making the project one of the biggest oil developments offshore Western Australia. Enfield and Laverda are to be developed first, via an FPSO over Enfield, with Laverda and, subsequently, Stybarrow tied back via subsea flowlines – the addition of Stybarrow will boost production to 100,000 b/d. Field life is put at 15 years. South Korea's Samsung Heavy Industries is to build the Enfield FPSO. The double-hulled vessel will have a storage capacity of 900,000 barrels.

Gas, however, is increasingly seen as the fuel of the future, with Western Australia's North West Shelf project playing a key role. China is particularly keen to secure gas supplies, striking a deal with the North West Shelf Venture partners in 2002 under which CNOOC will take a 5.3% stake as part of a \$25bn to \$30bn contract to sell between 3mn and 4mn t/y of LNG to Guangdong Province for 25 years from 2006 (see *Petroleum Review*, November 2003). The project will supply LNG to a number of other Asia-Pacific markets, including Japan.

On a more disappointing note, North West Shelf Gas recently stated that the amended conditional gas sale and purchase agreement between Methanex Australia and participants in the North West Shelf Venture lapsed on 30 September 2003 after Methanex announced that it would not be proceeding with its proposed methanol project on the Burrup Peninsula in Western Australia. The two organisations first signed a sale and purchase agreement on 20 December 2001 for the supply of 200 TJ/d of gas over 25 years from 2005. This was later extended by a further 130 TJ/d over 16 years, starting in 2006. Methanex is now studying an alternative design for the support of its long-term methanol supply to its customers in the Asia-Pacific from the Burrup.

The Greater Gorgon gas fields project is one of the larger developments in Australia, comprising a number of fields offshore the Burrup Peninsular offshore Western Australia (see **Table 2**). China has expresed an interest in Gorgon reserves, with CNOOC recently signing an agreement with ChevronTexaco (operator), Shell and ExxonMobil to begin talks on upstream investment in the project. The Chinese company has also agreed to explore marketing opportunities for Gorgon gas in China.

In September 2003 the Western Australian state government gave in-principal approval to ChevronTexaco to use Barrow Island as the site for the processing facilities for its proposed A\$11bn development of the Gorgon offshore gas field. The approval to use the site is conditional on the joint venture meeting strict state and commonwealth environmental safeguards. ChevronTexaco already operates a 40-year-old oil production facility on Barrow Island, which is a Class A nature reserve administered by the state government.

SEA gas pipeline under construction – the pipeline will play a key role in supplying South Australian demand

The Greater Gorgon gas project will include development of ExxonMobil's Io/Jansz field. A recent test of the Jansz-3 appraisal well flowed gas at a maximum rate of 72mn cf/d – confirming the discovery as Australia's largest gas find, with reserves put at 20tn cf of recoverable gas.

Looking to recent licensing activity, a total of six permits were granted in the Western Australia, Victoria, Tasmania and Northern Territory after bidding closed on 10 April 2003. Woodside Petroleum secured new exploration permits WA-347-P and WA-348-P in Western Australia's Carnarvon Basin, in deepwater areas where there has been little previous exploration. Nexus Energy was awarded permit Vic/P56 in the Gippsland Basin, with Basin Oil, Santos and Diamond Gas Resources securing permit Vic/P55. A joint venture between Santos and Unocal was awarded permit T/35P in the Otway Basin, while Santos on its own was awarded permit NT/67 off northern Australia, which lies adjacent to the Turtle and Barnett oil discoveries and close to the likely pipeline route from the Woodside-operated Blacktip gas field in the Bonaparte Gulf. Over A\$60mn (\$41mn) is to be spent exploring the three new areas in the Bonaparte and Carnarvon Basins over the next six years.

The closing date for the first round of the 2003 acreage release – comprising some 35 new areas – closed on 25 September. Bidding for re-released acreage also closed on that date. Bids are currently being assessed. An indication of the areas proposed for release in the 2004 offshore acreage release – slated for March 2004 – was expected to be announced as *Petroleum Review* went to press.

In August, BHP Billiton Petroleum reported that it was planning to embark on its most extensive exploration drilling programme in Australian waters for more than a decade in a bid to find replacement reserves for production that is declining in two of the company's most important revenue sources. Much attention will focus on the northern margin of the Gippsland Basin fields in the Bass Strait where BHP and its partner ExxonMobil are looking for new reserves below the coal seams that extend beneath the existing known reservoirs.

Fields due to come onstream in 2003 include the Eni-operated (65%) Woollybutt field offshore the north-west coast, which produced first oil in May 2003. With a target plateau rate of 35,000 b/d forecast to be achieved this year, oil is being produced via two subsea wells linked to a double-hulled FPSO. Partners are ExxonMobil (20%) and TAP (15%).

Recent discoveries include Apache's Crosby-1 well, which discovered oil in the Exmouth Sub-Basin offshore Western Australia. The well, drilled to a measured depth of 4,022 ft, encountered a 112-foot oil column in the Pyrenees horizon of the Cretaceous-age Barrow Group. Apache has a 28.57% working interest in the well. BHP Petroleum is the operator with the remaining interest. Crosby's development costs are expected to be relatively low, as it could be developed in conjunction with the nearby Ravensworth discovery.

Moving across the country, the \$500mn South East Australian (SEA) gas pipeline from Victoria to South Australia is reportedly nearing completion as the final stages of the 690-km link at Pelican Point are put in place (see p22). According to South Australian

Country/Field	Operator	Oil or Gas output	Start-up date	Oil res. (mn b)	Gas res. (bn cf)	Capex ($mn)	Production system
AUSTRALIA							
Angel	Woodside	gas/cond	2010	–	1,800	–	platform
Patricia/Baleen (Bass Strait)	OMV	gas	2002/3	70	52	–	subsea
Bambra	Apache	gas/cond	2004	0.7	30	–	wellhead plat via Harriet
Blacktip (Bonaparte Gulf)	Woodside	gas	2007	–	1,100	–	potential 2.53mn cm/d
Brecknock/Scott Reef	Woodside	gas/cond	2010+	228	18,400	–	poss LNG development
Chrysaor/Dionysus*	Wapet	gas	2010/12	75 (cond)	3,988	150	*part of A$10 bn project
Dixon-Castor	Woodside	gas/cond	2005/10	–	–	–	FPSO, gas to Echo-Yodel
Dockerell/Keast	Woodside	oil/gas/cond	2005/10	–	–	–	to Echo-Yodel or Goodwyn
East Pilchard	Esso Australia/BHP	gas	2005+	–	–	–	
Echo-Yodel	Woodside	gas/cond	mid-2002	37 (cond)	400	200	2 subsea via Goodwyn A
Enfield (WA-271-P)	Woodside	oil/gas	4Q2006	146	–	882	FPSO (900,000b)
Evans Shoal	Shell Australia	gas	2005/09	–	10,500	–	poss supply Darwin LNG, 7.5 mn t/y?
Geryon*	ChevronTexaco	gas		103 (cond)	3,320	–	–
Gypsy/Rose/Lee	Apache	oil/gas	2002/03	7	150	–	wellh'd plat to Varanus Is
Golden Beach	Santos	gas	2005+	–	50	–	–
Gorgon*	Chevron/Texaco	gas	2012	316 (cond)	18,379	–	poss 6mn t/y LNG plat
Iago*	ChevronTexaco	–	–	89 (cond)	977	–	–
John Brookes	ExxonMobil	gas/cond	under eval	–	450	–	–
Kipper (Gippsl'nd Basin)	ExxonMobil	oil/gas	2006	13	575	263	–
Laminaria Phase 2	BHP	oil	2002	21	–	130	2 horiz wells. 65kb/d peak
Laverda	Woodside	oil	2006+	56.3	–	–	via Enfield facils
Loxton Shoals/Sr/Trb	Woodside	gas	2005/09	–	5,000	–	Darwin LNG, 7.5 mn t/y?
Macedon/Pyrenees	BHP	gas	under eval	–	–	–	–
Manta/Basker/Gummy	Woodside	oil/gas	2003/06	26	260	–	FPSO and subsea
Minerva/La Bella (Otway)	BHP	gas	2004	1	360	–	subsea or monotower
Mutineer-Exeter Cnvrn Bas	Santos		mid-2005	100	–	283	–
Nappamerri Trough	Santos	gas	end-2003	–	–	–	–
Nasutus	Apache	oil	under eval	–	–	–	–
Orthrus/Maenah*	ChevronTexaco	gas	–	31 (cond)	1,199	–	–
Perseus/Athena	Woodside	gas/cond	1999 on	–	7,600	–	North Rankin and subsea
Petrel/Tern	Santos	gas	under eval	–	2,700	–	–
Ramillies	BHP	oil	2002+	2	–	–	–
Rankin-Sculptor	Woodside	gas/cond	2005–10	–	–	–	subsea to Echo-Yodel
Reindeer	Apache	gas	under eval	–	350	–	–
Scarborough	ExxonMobil	gas	2010+	–	8,000	4,700	supply proposed LNG?
Searipple	Woodside	gas/cond	2005+	–	50	–	with Perseus via N Rankin
Spar*	Chev/Tex/Ampol/Shell	gas	2012	11 (cond)	350	–	–
Tenacious	OMV	oil	under eval	5	–	42	tie-back to Jabiru
Tern/Petrol B'nap'te Glf	Santos	gas	2008+	–	3,000	–	platform or FPS
Tidepole	Woodside	cond/gas	2013	14 (cond)	420	–	–
Thylacine Otway Basin	Woodside	gas	2006	–	436	170	wellh'd plat + 5 subsea
Geographe Otway Basin	Woodside	gas	2006	–	364	170	3 subsea manifold
Urania*	ChevronTexaco	gas	–	8 (cond)	266	–	–
Vincent (WA-271-P)	Woodside	oil	2006+	117.4	–	–	via Enfield facils
West Tyral Rocks*	Wapet	gas	2010	98 (cond)	3,513	–	–
Wilcox	Woodside	gas/cond	2010	–	300	–	to Goodwyn or Echo-Yodel
Yolla (Bass Basin)	Origin Energy (ex Boral)	oil/gas/cond	mid-2004	45 (cond)	300	240	platform 49mn cf/d,5kb/d
Woollybutt	Eni	oil	May–03	25	–	30	2 subsea to FPSO
KEY DISCOVERIES							
Lynx/Vega	Woodside	gas	–	–	–	–	–
Casino Otway Basin	Santos	gas	–	300	–	–	–
Jacaranda Otway Basin	Boral Energy	oil	–	–	–	–	–
Ravensworth (Exmouth)	BHP Billiton	oil	–	–	–	–	–
Tregony (PEP 153)	Santos	gas	–	–	–	–	potential 10–15 mn cf/d
Sybarrow (Exmouth Basin)	Woodside	oil	–	50	–	–	–
Io/Jansz*	ExxonMobil	gas	–	120 (cond)	20,000	–	joint dev'p'nt Gorgon
Titanichthys	Inspex Browse	gas/cond	–	700mn boe	–	–	–
Gorgonichthys	Inspex Browse	gas/cond	–	2,339mn boe	–	–	–
Brecknock South	Woodside	gas/cond	–	88	3,900	–	–
TIMOR GAP-ZOCA							
Greater Sunrise**	Shell	cond/gas	2006+	300	9,160	–	with Bayu Undan/float LNG
Laminaria East	BHP	oil	–	–	–	–	close to Buffalo field
Bayu-Undan	Phillips	cond/gas	Apr-04	404	–	1,696	3 platforms, ph1 liquids
Bayu-Undan	Phillips	gas/LNG	2H2006	–	3,400	–	phase 2 LNG
Jahal	BHP	oil	–	–	–	–	–
NEW ZEALAND							
Kahii	Indo-Pacific	oil/gas	mid-2004	–	–	–	–
Kauhauroa	Westech	gas	presently uncommercial		–	170	–
Kauri	Swift Energy	oil	eval	4	264	250	platform
Kupe South	Shell	gas/oil	2008+	25	–	170–300	FPSO + subsea
Maari	OMV New Zealand	oil	late 2005	–	101	213	onshore
Mangahewa	Shell	gas	2001	53 (cond)	1,000	170–300	–
Phokura	Shell	gas/cond	2006+	27 (boe)	–	–	–
Rimu	Swift Energy	oil/cond	1Q2002	–	–	–	–

Greater Gorgon comprises 851mn b of condensates and 52tn cf of gas – see* **Table 2
***Greater Sunrise comprises Sunrise, Sunset and Troubadour fields*

Table 1: Current and planned field developments in the Asia-Pacific region

Note: See November issue for Part 1 of the table


The SEA gas pipeline is to be commissioned in January 2004

Energy Minister Patrick Conlon, the pipeline is 'one of the most important pieces of infrastructure ever constructed in South Australia – doubling the amount of gas available to South Australians. That means added security of supply for gas and electricity and increased competition in the gas market, which will help put downward pressure on prices.'

Some 70% of South Australia's electricity is generated from gas and the state has previously been totally reliant on the Moomba-Adelaide gas pipeline. The SEA pipeline project is in the joint ownership of the equal participants International Power, Origin Energy and TXU Australia.

Meanwhile, the joint venture partners in the Otway gas project committed \$26mn of investment in design engineering and project planning following the selection of the preferred development concept. The project covers the Geographe and Thylacine gas fields in the offshore Otway Basin. The proposed development concept comprises a wellhead platform with five production wells on Thylacine, a subsea manifold and three production wells on Geographe. Gas will be processed at an onshore plant near Port Campbell. The project is expected to produce 60 PJ/y, supplying around 10% of south-eastern Australia's current gas demand from 2006 for 10 years. Partners are Woodside (51.55%, operator), Origin Energy Resources (29.75%), Benaris International (12.7%) and CalEnergy Gas (6%).

In other news, Santos, operator of the Vic/P 44 permit in the Otway Basin offshore Western Victoria, concluded a new long-term gas contract with TXU Australia to supply gas from the Casino gas field. The contract is conditional on the results of the next Casino appraisal well, which commenced drilling in October. If the Casino 3 well is successful, gas supply will commence in 2006 and extend through to 2017. TXU has agreed to purchase up to 293 PJ of gas from the block, with an option to purchase up to an additional 200 PJ.

Earlier in the year, Woodside (45.94%) reported that a new horizontal development well had increased production by 17,000 b/d to 46,000 b/d at the Legendre oil field offshore Western Australia. Total field production in 2003 is now forecast to reach 10mn barrels. Proved and probable reserves are put at 40.1mn barrels. The field has produced 22mn barrels to date and has a remaining field life of three to four years. Field partners are Apache (31.5%) and Santos (22.56%).

	Condensate mn/b	Gas bn cf
Gorgon	316	18,379
Chrysaor/Dionysus	75	3,988
West Tryal Rocks	98	3,513
Spar	11	350
Geryon	103	3,320
Orthrus/Maenad	31	1,199
Urania	8	266
Io/Jansz	120	20,006
Iago	89	977
Total	**851**	**51,998**

Table 2: Greater Gorgon fields

EAST TIMOR–AUSTRALIA JPDA

Final approval was reported in June to have been given by the Timor Sea Designated Authority for the \$1.5bn Bayu-Undan LNG project offshore Australia. Estimated field reserves are put at 400mn barrels of condensate and LPG, together with 3.4tn cf of gas. A 3mn t/y LNG plant is to be built at Wickham Point, in the Northern Territory.

Bayu-Undan LNG is to be sold to Tokyo Electric Power and Tokyo Gas over a 17-year period beginning early 2006. ConocoPhillips (64.2%, operator) has sold the Japanese customers a 22.5% stake in PSC 03-13, which equates to a 10.08% interest in the unitised Bayu-Undan field, pipeline and LNG plant. Project partners are Santos (11.8%), Inpex (11.7%) and Eni (12.3%).

The go-ahead was given for the \$1.8bn liquids stripping project at Bayu-Undan in late 1999, with final approvals secured to begin that phase of development in early 2000. The liquids project is due to begin production in early 2004, ramping up to full output of around 100,000 b/d by mid-year.

Final approval for the LNG part of the project was initially delayed by Australia's failure to ratify the new

Timor Sea Treaty by the appointed date of 31 December 2002. The Treaty, which splits revenues from the Joint Petroleum Development Area (JPDA) on a 10:90 basis between Australia and Timor-Leste (East Timor), was finally ratified on 5 March 2003.

It is reported that East Timor will receive \$1mn (A\$1.6mn) a year for at least five years under the revenue-sharing agreement. In addition, the new nation will receive \$10mn a year from the Australian Government, over and above its share of revenues, once production from the Greater Sunrise reservoir begins. However, this may be some time away, as a recent study by Woodside – conducted on behalf of the project partners in June 2002 – determined that the domestic gas proposals were not economically viable in the current market conditions. The joint venture is now examining an LNG development for the field, targeting Asian customers and the US West Coast.

PAPUA NEW GUINEA

It is hoped that the development of Papua New Guinea (PNG) gas reserves will eventually take off with the commissioning of the proposed \$6bn gas export pipeline between PNG and Australia. Although still struggling to find customers for the 150 PJ/y of gas necessary to make the project commercially viable, operator ExxonMobil and partner Oil Search recently signed an agreement to continue to market the concept. The new agreement is reported to offer the partners 'more flexibility' in terms of decision making. The joint venture also now includes the Angore and Juha fields that replace production acreage lost with the departure of ChevronTexaco from the project.

In other news, Oil Search has paid \$96.6mn in order to take over from ChevronTexaco subsidiary Chevron Nuigini (CNGL) as operator of various assets in PNG. It will act as operator of Petroleum Development Licence 2 (Kutubu), Pipeline Licence 2, Moran Unit, Petroleum Development Licence 4 (Gobe Main), SE Gobe Unit, Pipeline Licence 3, and Petroleum Prospecting Licence 219. As part of ChevronTexaco's withdrawal from PNG's E&P sector, the company has also handed over operatorship of Petroleum Retention Licences 2 (Juhu) and 3 (P'nyang) to Esso Highlands.

Meanwhile, Canadian oil company InterOil discovered 14 new oil shows in Papua New Guinea through 135 metres of cored tertiary limestone in the Moose-1 ST1 well in the Gulf Province. Additional testing, production and development drilling is to be undertaken in order to determine the structure's resource potential. Commercial confirmation would result in the first significant hydrocarbon discovery in the area in 44 years, said the company.

NEW ZEALAND

The current environment for exploration in New Zealand is reported to be 'better than at any time in the past 30 years'. The earlier than anticipated depletion of the Maui gas condensate field in the offshore Taranaki Basin and the projected rise in demand for gas for electricity generation is pushing up gas prices – as a result the gas market is fast becoming a sellers market.

The 2003 onshore Taranaki and offshore North Taranaki bidding round, which closed on 31 October, included nine offshore blocks and eight onshore blocks covering a total area of 12,772 sq km. The offshore blocks are in water depths between 50 metres and 200 metres, extending north from Cape Egmont to an area west of Kawhia Harbour. The onshore blocks are located in an area bound by Cape Egmont to the west, Mt Taranaki to the south and Urenui to the east, and are immediately adjacent to several producing fields and recent discoveries.

A total of 23 bids were received for the 17 blocks on offer. Some 17 companies made bids, including four New Zealand outfits. Awards are expected to be announced in the New Year. A condition of the blocks offer was that an exploration well must be drilled within four years of the commencement date of the permit, although many of the bids received are reported to involve well drilling earlier than this.

A bidding round is anticipated over an area offshore the Northland Basin, which lies immediately north of the productive Taranaki Basin, in 2004. Initial interpretation, together with the results of Wakanui-1 are reported to indicate that Northland is 'highly prospective'. Permit boundaries have yet to be confirmed and planning continues. In preparation for the bidding round, the Ministry of Economic Development's Crown Minerals Group has joined forces with the Institute of Geological and Nuclear Sciences (GNS) and UK-based seismic contractor Spectrum Energy & Information Technology to produce a substantial data-package on the basin's petroleum prospectivity.

In other news, OMV recently sold a 9.8% stake in the Pohokura gas condensate field to its consortium partner Todd Petroleum Mining, together with shares in three other exploration licences in New Zealand, for an undisclosed sum. The sale reduces OMV's stake in Pohokura from 35.8% to 26%. Other partners are Shell and Preussag Energie. Located in the Taranaki Basin, Pohokura is the largest undeveloped gas field in New Zealand with reserves put at some 1,000bn cf of gas and 53mn barrels of condensate. It is currently being appraised with the aim of commencing production in 2006. The field will help replace the diminishing reserves of the Maui field that currently supplies 80% of New Zealand's gas demand. Maui is expected to reach the end of its productive life in five years.

In September, the New Zealand Commerce Commission authorised the project partners to jointly market and sell gas produced from Pohokura rather

New Zealand Refining Company's refinery at Whangarei, North Island

By signing a greenhouse agreement with the crown, NZ Refining will be exempt from emission charges

than sell it in competition with each other. The Commission stated that while it usually preferred separate marketing because competition allowed purchasers of the gas to negotiate lower prices and better terms and conditions when they had a choice of supplier, the Pohokura decision reflected the fact that 'in certain circumstances the development of gas fields may require a joint venture approach in order to make the gas available to the market as quickly as possible'.

Other projects include the Maari oil field offshore Taranaki, which is due onstream in late 2005 at an initial rate of 30,000 b/d of oil. Partners are OMV New Zealand (39%), OMV Australia (30%), Todd Petroleum (16%), Horizon Oil (10%) and Delta Oil Taranaki (5%). The field is estimated to hold 25mn barrels of reserves. An FPSO, subsea wellheads and horizontal water injectors figure in the development plan.

Earlier this year US oil and gas company Westech Energy was reported to have said that recent 2D seismic had indicated a prospect offshore New Zealand's Wairarapa coast that could possibly be as large as the giant Maui gas field. The company is seeking partners to share the risk of drilling a well to establish if gas is present.

Looking downstream, the New Zealand Refining Company (NZRC) is to spend $180mn on developing cleaner fuels after becoming the first firm to sign a negotiated greenhouse agreement with the Crown. By signing the agreement, NZ Refining will be exempt from planned emission charges.

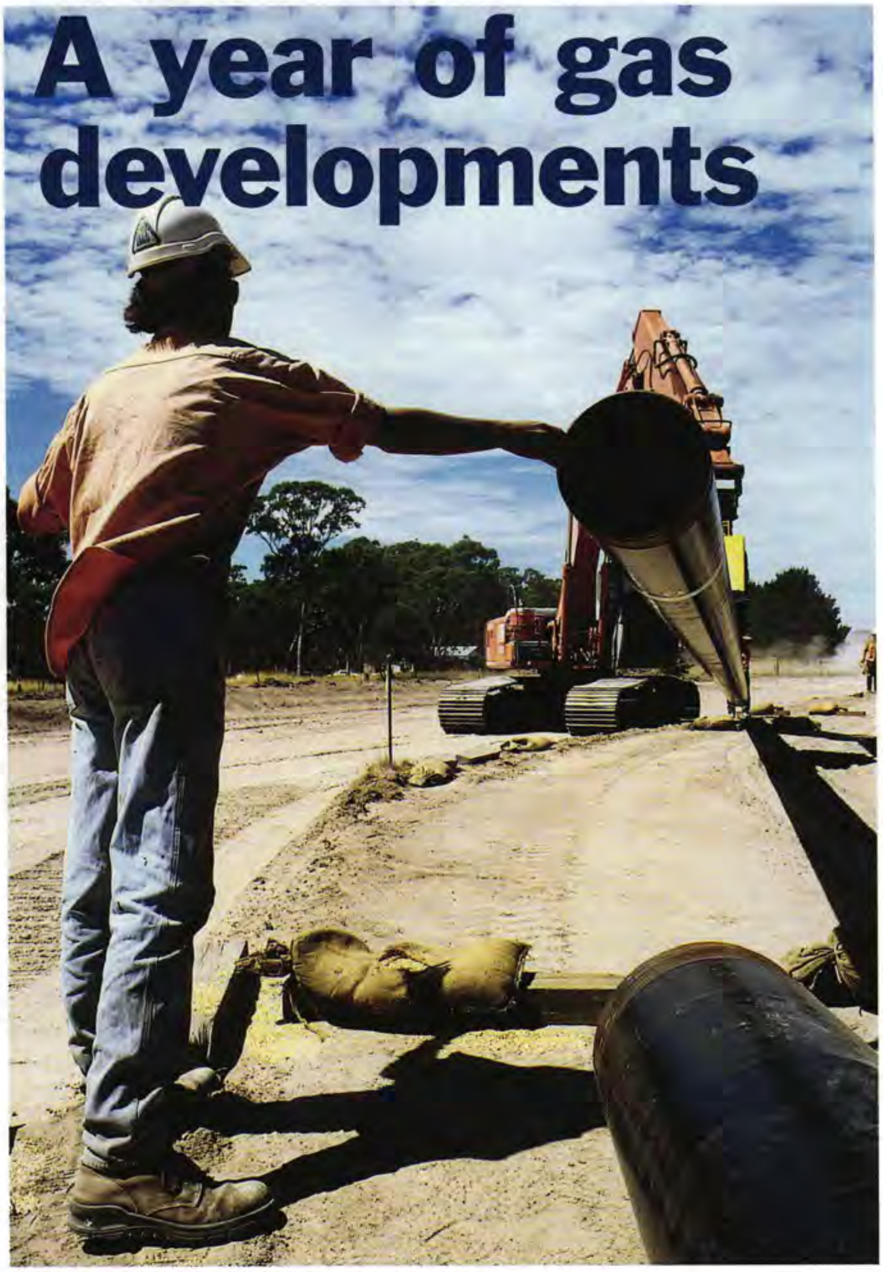
Foster Wheeler is to assist NZRC in its 'Future Fuels' clean fuels project that involves the modification of New Zealand's sole refinery, located at Whangarei, North Island, to produce low-sulphur diesel fuel and low-benzene, low-sulphur and low-aromatics gasoline. This is required to ensure compliance with changes to New Zealand's national transport fuel specifications, which are due to enter force from 2004. These will be followed in 2006 by specifications requiring a reduction in the sulphur content of automotive diesel fuel to 50 ppm or less and a reduction in benzene (1% by volume), sulphur and aromatics content in motor gasoline.

The project, which is expected to cost NZ$180mn ($90mn), is split into two stages. Stage One involved Foster Wheeler helping to develop the engineering, procurement and construction (EPC) sanction package. The company secured the contract for Stage Two – the EPC phase – in mid-May 2003.

The refinery currently produces 106,000 barrels per stream day (t/sd). The Future Fuels project includes new processing units for benzene removal, hydrodesulphurisation and hydrogen separation, as well as a significant revamp of existing facilities. Expected throughput from the new units is: 3,600 t/sd from the hydrodesulphuriser, which uses Shell Research and Shell Global Solution International's technology, and 2,900 t/sd from the benzene removal unit, which will use UOP's Bensat technology. Start-up is scheduled for August 2005.

Petroleum Review *would like to thank Wood Mackenzie for its help in putting together this review.*

A year of gas developments



There were some important infrastructure, policy and regulatory developments for the Australian downstream gas industry in 2003, signalling a positive year ahead for the sector, writes *Bill Nagle*, Chief Executive of the Australian Gas Association (AGA).*

Looking back on my contribution to the December 2002 edition of *Petroleum Review*, it is clear that the Australian Gas Association (AGA) wanted to see 2003 deliver on a number of key regulatory and policy issues for the Australian downstream gas industry. In a number of respects, it has not been disappointed.

Importantly, Australia's Federal, State and Territory Governments (through the Council of Australian Governments and the Ministerial Council on Energy) have progressed work on a national energy policy for Australia, while the Productivity Commission has commenced a wide-ranging review of the operation of the national gas access regime (including the National Gas Code). This regime is the principal economic regulatory instrument covering Australia's downstream gas distribution and transmission infrastructure assets.

These positive developments have been complemented by some key developments within the downstream gas industry itself, including:

- The completion of Duke Energy International's major underground and subsea gas pipeline from Victoria to the island State of Tasmania, and the Tasmanian Government's selection of New Zealand-based Powerco as the preferred developer of a backbone gas distribution network to key centres within the State.
- The construction of the major SEA Gas transmission pipeline between Victoria and South Australia, which is scheduled to be in commercial operation by January 2004. This pipeline is being developed by a consortium comprising TXU, Origin Energy and International Power.
- The development of Australia's first gas trading hub, VicHub, which was commissioned during the year by Duke Energy International. Construction of the hub involved the interconnection of the Eastern Gas Pipeline near Longford, Victoria, the Tasmanian Gas Pipeline and GasNet's Victorian gas transmission system. A further hub is also expected to evolve at Iona, in south-west Victoria.
- The continued development of additional gas fields for domestic supply (particularly off the southern coast of Victoria), and an increased focus on the development of coal bed methane resources (particularly in New South Wales and Queensland).
- The commissioning of some new gas-fired power generators in recent years, with various proposals currently also on the table regarding the construction of further gas-fired power plants in a number of locations around Australia.

Gas in the pipeline

Additionally, a proposal is still being considered for a pipeline to bring gas from Papua New Guinea to Australia for use by the domestic market. This pipeline would extend from PNG to Queensland or the Northern Territory, and would then likely take gas into the south-eastern Australian markets largely through the existing pipeline network. A final decision to proceed with front-end engineering and design (FEED) on the pipeline, however, remains dependent on sufficient foundation gas customers being confirmed in Queensland or the Northern Territory (see p16).

Meanwhile, the medium- to long-term potential to pipe gas from Western Australia to eastern Australian markets is also back on the agenda after a long absence.

LNG exports

It is also worth noting that there have been a number of major LNG export developments for Australia during the past few years. In 2002, Australia exported 7.6mn tonnes of LNG, much of which was exported to Japan by the North West Shelf project. This consortium also entered into an agreement in 2002 to sell China 3mn t/y of LNG for 25 years (commencing from 2005–2006), and also signed a term contract in 2003 for LNG exports to South Korea (see *Petroleum Review*, November 2003).

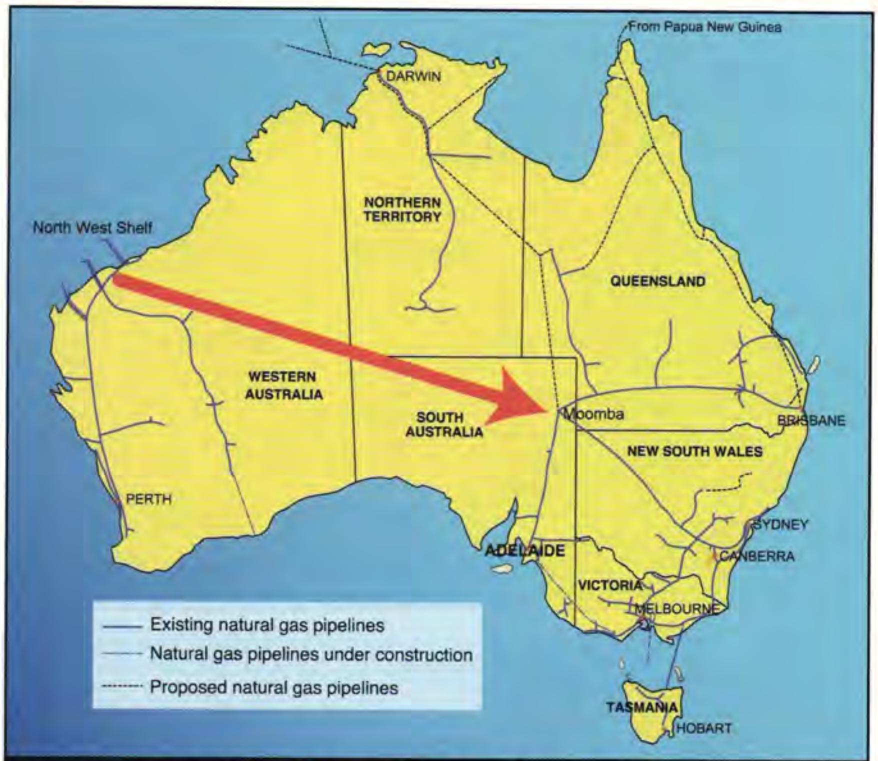
It is worth noting that in late October, China National Offshore Oil Corporation (CNOOC) and the joint venture proponents of the Gorgon gas development, located offshore Western Australia, signed an agreement that the joint venturers expect will lead to significant volumes of Gorgon LNG being used in the growing Chinese market in the future. At the time of the announcement, the agreement was subject to the completion of formal contracts – however, Western Australia's Premier, Geoff Gallop MLA, said it could lead to an export deal bigger than that between the North West Shelf Project and China.

Additionally, a second LNG export project for Australia, using gas from the Bayu-Undan gas field in the Timor Sea, is to supply LNG to initial Japanese customers from early 2006. Gas will be piped from the field to a gas liquefaction facility near Darwin, for processing prior to export. The project is operated by US company, ConocoPhillips. (See p16.)

Other prospects to pipe gas from the Timor Sea to southern Australian markets have waned in the past year, however.

National energy policy

In a welcome move, Australia's Federal, State and Territory Governments continued their development of a national energy policy during 2003 – something that has eluded the nation since Federation in 1901.



There is a medium- to long-term potential to pipe gas from Western Australia to eastern Australian markets via Moomba

The AGA has consistently argued that the relatively positive outlook for the Australian gas industry could be supported further by government policies that facilitate gas market growth, particularly by promoting gas-fired electricity generation, cogeneration, and domestic and industrial fuel-switching. Such policies particularly relate to greenhouse emissions abatement, market regulation, taxation and regional development.

The AGA believes that the national energy policy would enable many of these outcomes to be progressed.

In 2001 the Federal, State and Territory Governments announced that an expert panel would undertake an Energy Market Review (EMR) as a first step in developing the national energy policy. In announcing this measure, the governments explicitly recognised the important role that natural gas should play in the policy, given its domestic abundance, flexibility and greenhouse benefits.

The EMR handed down its Final Report in December 2002, and the AGA welcomed many of its recommendations for energy market reform. These recommendations were positive for the development of Australia's gas distribution and transmission network, particularly in calling for significant improvements in the current access pricing regulation applying to the sector.

Recommendations made by the EMR included:

- The need to commence an independent review of the national gas access regime (including the National Gas Code), to address the deficiencies with current access regulation relating to the downstream gas sector. (As noted elsewhere in this article, this review is currently being undertaken by the Productivity Commission).
- The need for greater upstream gas market competition.
- Application of the principle that significant regulatory decisions should be subject to clear merits and judicial review.
- The need to avoid caps on retail energy prices, following the introduction of retail competition.

The EMR also endorsed the need for a 'technology neutral' approach to greenhouse emissions abatement policy and recommended that an economy-wide emissions trading system be implemented in Australia to achieve a more cost-effective approach to greenhouse abatement.

Additionally, it recommended the establishment of a single national energy regulator. The Federal, State and Territory Energy Ministers have since announced that such a regulator will be developed. Initially, it will oversee transmission and wholesale electricity prices, but it is also likely to take responsibility for gas transmission matters within 12 months of its establishment. A wholesale gas market regulatory mechanism is currently on the backburner.

Above and main picture: Construction of the SEA Gas pipeline, which extends between Port Campbell (Victoria) and Adelaide (South Australia), commenced in October 2002. First commercial gas remains on track to flow through the pipeline in January 2004

The AGA also welcomed the EMR's recommendation that 15-year 'economic regulation free' periods be introduced for greenfields gas transmission pipelines, in order to encourage the development of such infrastructure. However, the Association stressed that greenfields gas distribution network extensions and augmentations should also be included in such a measure.

The AGA anticipates that the Federal, State and Territory Governments will work to finalise the national energy policy during 2004. It remains confident that increasing the role of natural gas in Australia's energy mix will be a key aim of the policy.

Gas access regime review

The Productivity Commission's commencement of a wide-ranging review of the operation of the national gas access regime (including the National Gas Code) was a significant development this year. The AGA has argued for some time that, while the original aim of the regime (upon its introduction in 1997) may have been to implement balanced, light-handed, flexible and incentive-based regulation, it has not delivered on these intentions. Rather, it has tended to produce inflexible, 'rate of return' style rulings that have not adequately reflected the interests of consumers in encouraging investment in an expanding and reliable gas network.

Such rulings have, in fact, deterred investment in the further development of the gas network and, critically, ongoing re-investment in existing gas infrastructure. Numerous proposals for new gas distribution networks and for pipelines have been adversely impacted by the restrictive nature and application of the regime. (Indeed, most of the pipeline infrastructure developments referred to earlier in this article have occurred outside the National Gas Code regime – they will be 'uncovered' pipelines).

Given its concerns with the regime to date, the AGA has welcomed the commencement of the Productivity Commission's review.

In a submission to the review, the AGA has argued that the National Gas Code could be improved through the incorporation of clear access pricing principles, to guide regulators in making decisions that better reflect the medium and long-term interests of the Australian community in having access to an expanding and reliable gas network.

The review should also focus on ways to overcome the identified flaws in existing access pricing regulation, by promoting simpler and more light-handed pricing approaches. A number of recent judicial decisions have emphasised the costs and flaws of highly theoretical and unbalanced approaches to access pricing regulation.

The AGA also believes that specific mechanisms to facilitate new investment in gas infrastructure, such as the 'access holidays' recommended by the EMR, should be finalised and implemented quickly.

The Productivity Commission is required to report to the Federal Government on its review by mid-2004.

Looking ahead

With both the review of the gas access regime and the decision-making phase of the national energy policy currently underway, the AGA anticipates that 2004 will be an important and positive year for Australia's downstream gas industry.

Both these processes provide a 'once in a decade' opportunity for government policy and regulation to encourage the further development and expansion of Australia's gas distribution and transmission network, particularly to regional areas.

This would ensure that the economic, regional and environmental benefits of natural gas delivered to more Australian communities.

**The Australian Gas Association (AGA) is the national representative body for Australia's downstream gas industry. Its principal membership comprises gas distribution, retail and pipeline companies, in addition to gas appliance and equipment manufacturers.*

Further information on the AGA and its work can be found at **www.gas.asn.au**

The AGA can be contacted at e: canberra@gas.asn.au

Get Smart – the digital oil field is coming

The glamour has worn off 'e-biz' in the oil and gas sector. E-procurement and e-auctions in particular have been slow to take off, although e-trading and e-logistics continue to perform well. However, there's a new game in town, which targets digital technology where it really counts. New initiatives are underway by the majors, focused on optimising all aspects of asset development, management and lifecycle costs, reports *Brian Davis*.

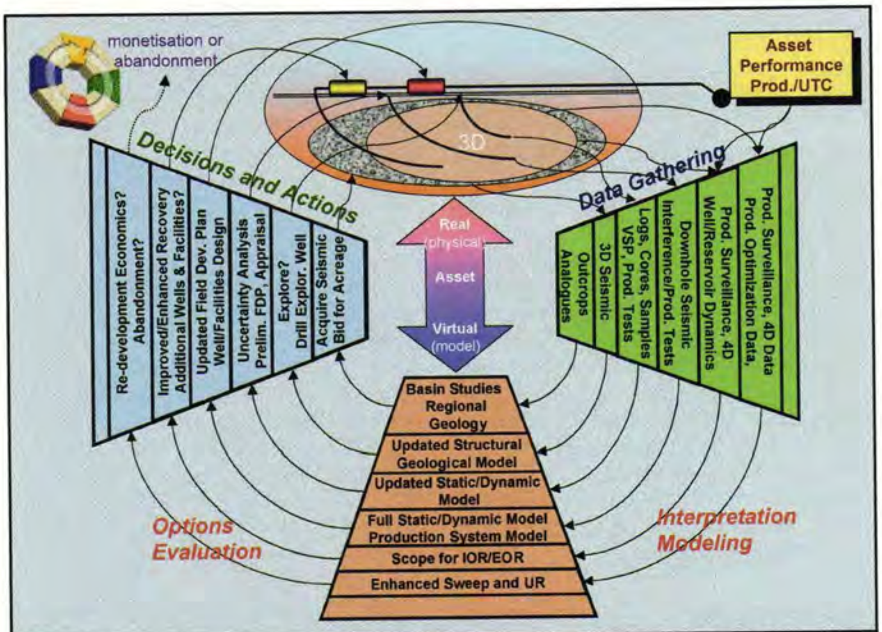


Figure 1: Key elements of the digital oilfield © Shell International

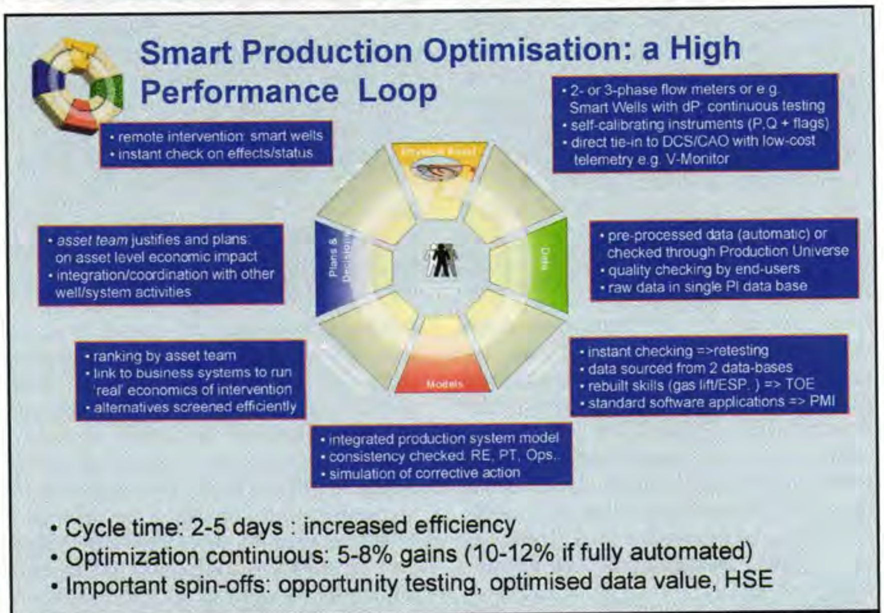


Figure 2: The Smart Loop octagram © Shell International

Shell calls its digital development concept Smart Fields©, BP talks of Field of the Future (formerly e-Fields, see box), while others speak of I-fields or digital oil fields, with POSC (Petrotechnical Open Standards Consortium) favouring the all-encompassing X-fields. Whatever the name, a concerted initiative is underway that demands new levels of collaboration and systems understanding, and promises serious benefits in a rapidly changing oil and gas E&P scenario.

The key to Smart Fields will be the use of real-time data, linked to detailed corporate know-how for business and process analysis and optimisation. Advanced sensors and sophisticated IT infrastructure will give a real-time picture of downhole and production operations, used in concert with advanced visualisation systems (for example, fed by 4D seismics) and business analysis tools – leveraged by e-enabled systems for increased productivity.

Key drivers

The big driver is not technology but the promise of significant cost savings combined with increased production and reserves recovery, particularly in remote and marginal fields. Most of the technology is available, but system integration will be a major challenge as no single IT provider currently covers all options.

There's also the critical question of standards. Discussions are underway with industry bodies like POSC and the Petroleum Internet Data Exchange (PIDX), to thrash out a consensus-driven path for leveraging Internet technology and the integration of oil and gas business processes.

Smart systems are a lot more about methodology than technology. Operators and partners aim to 'measure, model and control' an asset more effectively throughout its lifecycle. This means measuring and modelling 'actual' versus 'desired' performance, considering the options, deriving a corrective course of action, then executing it. This calls for continuous surveillance (using sensors) and model-based optimisation with intelligent problem analysis.

Estimates from Cambridge Energy Research Associates (CERA) recent *Digital Oilfield of the Future (DOFF)* multi-client study that Smart/digital systems have the potential to increase world oil reserves by 125bn barrels in the next six to 10 years.

Getting Smart

Pieter Kapteijn is Manager of Shell International E&P's Smart Fields development programme and sees the Smart Fields concept as 'integrating core processes to improve the decisions made during field development'. The programme is a key strategic theme for Shell and has been underway for about 20 months. The core Smart Fields team consists of 15 people, lead by Kapteijn, and supported by 30–40 staff in the regions.

The Smart Fields programme is focussed on the core management processes for production operations, production optimisation, well and reservoir surveillance, and field development planning – which are all typically IT-enabled. Opportunities are being identified for using new technology, new data, new workflow models and decision-making processes, so the performance and asset lifecycle costs can be enhanced significantly.

Shell is not afraid to set ambitious targets for the Smart Fields programme, despite the criticism of hype that surrounded earlier e-business initiatives. By 2008, the oil major plans to achieve at least 10% production improvement 'across the board', 5% improvement in recovery levels, 20% improvement in operating expenditure, and 75% reduction in cycle times of core technical processes around asset management.

Kapteijn emphasises that these targets represent 'maximum improvement' in each of these areas, but individual Smart Fields will not have all the above improvements simultaneously. For example, in some assets Shell aims for production improvement, in others the target is cost reduction. As a rule of thumb, 75% of the value increase comes from production and reserves improvements.

'Smartness' screening

Smart Fields calls for the application of advanced process control concepts to the integrated asset. The asset is treated as a single dynamic system from sub-surface well facilities, though the production system, and along the supply chain to the customer delivery point. If this seems a big picture – it is! About 90% of Shell EP's production comes from 120 assets. Depending on the business case, most could be a target for 'smartness'. All new projects are being screened for 'smartness' as the biggest savings come during the design phase.

Shell is concentrating on some early target production operations, to be followed by more advanced integration. Whereas earlier e-business initiatives like e-procurement were fairly static, Smart Fields depends on the use of continuously updated dynamic models. As the oil and gas industry enters a very mature phase, Kapteijn recognises that: 'Smart Fields offers an effective way to increase knowledge and data intensity, data capacity and improve collaboration to maintain margins as more marginal and complex fields are developed'.

BP's 'Field of the Future' initiative

BP's Field of the Future programme (formerly called e-Fields) is also targeted at optimising the real-time, continuous and remote monitoring, operation and management of assets from the reservoir to the point of sale.

According to Andy Leonard, Field of the Future Programme Manager: 'The Field of the Future programme is set to transform the way BP works, integrating upstream disciplines and enhancing HSE performance'. e-Enabled systems will facilitate faster management decisions, closely aligned with business models and market drivers. Strategically, the programme will help eliminate 'surprise' events in reservoir and facility performance by observing and controlling fluid movements more closely.

By 2005, BP plans to make near real-time acquisition of seismic images of the reservoir commonplace, with consistent digital architecture deployed throughout its assets. Visualisation systems will capture, monitor and analyse field data in real-time, with up-to-the-minute reviews of integrated reservoir, wells and facilities models. New portals and visualisation tools will give access to far more detailed data, interpretations and models.

World first

BP has already installed what it claims to be the world's first permanent seismic cable installation on the Valhall field in the Norwegian North Sea. The Life of Field Seismic (LoFS) project consists of 120 km of permanently installed seismic cables and over 10,000 geophones (sensors) connected to shore by fibre-optic cable. It will facilitate real-time reservoir management, secure base reserves and increase recovery and production from the field. The $40–$50mn project involves 30 new wells on the Valhall flank.

Working in a collaborative online environment, members of the asset team will have greater access to peers and experts, sharing best practice. What's more, increasingly automated systems will boost safety as the team becomes less exposed to hazardous environments.

With the benefit of remote monitoring and control, the asset will have improved flow assurance and well integrity, more production up time, and help optimise existing wells and reservoirs. Significant benefits will be gained using advanced reservoir planning, and a more holistic picture of the reservoir and sub-surface facilities in real-time. This will result in better use of choke models, with enhanced data and remote response.

Leonard emphasises: 'Field of the Future promises faster, more efficient decision-making. Teams will be better integrated between disciplines, with improved global understanding, in a sustained culture of process change.' Decision-making will be supported by the latest Internet-based technology. Production will be more closely aligned to market factors, and personnel at all levels will have access to data and models.

Real-time data capabilities will be scaled up across BP's E&P operations. The ultimate goal is to achieve better system integration, so new systems and applications can be added to the IT infrastructure on a 'plug and play' basis. The Field of the Future strategy is likely to reduce future integration and customisation costs dramatically. As the programme progresses broader business processes will be added for improved performance management, procurement and management information, in a real-time data architecture.

Projects to date

Five Smart Fields optimisation projects have been undertaken so far – in operations in Gabon, Sarawak Malaysia on South Furious, in the Brunei Shell Petroleum (BSP) Smart Wells Project, at the Shell EP operation in the US, and some related projects. 'The results give us confidence that our targets are realistic,' says Kapteijn, and are in line with CERA's *DOFF* study of digital technology projects that promised production improvements of 5–10% and recovery improvements of 3–5%.

Technology will play a key role, but the oil industry lags well behind e-pioneers in the auto industry, aerospace and even the downstream process industries. Smart Fields systems will require acquisition of vast volumes of data – eg for distributed temperature and pressure sensing (DTS/DPS), 4D and micro-seismics, composition and three-phase flow. Low cost telemetry and fibre-optics will be deployed to transport, process and manage data. Software tools must become more interoperable for better decision-making workflows, visualisation, simulation and knowledge management. There will also be a need for advanced control and optimisation systems, and new ways to maintain and operate assets remotely (such as e-maintenance of rotating equipment).

Smart philosophy

The philosophy behind Smart production optimisation is represented by a high performance 'value loop' around the four EP 'assets', shown in an octagram – physical asset, data, models, plans and decisions (see **Figure 1**). As one moves around the octagram clockwise, the aim is to gather data continuously, interpret and model, evaluate options, then make decisions and act. 'The theory is to combine these four assets in a structured, integrated way, using enabling technology, to close the performance loop and generate most value,' Kapteijn explains.

Taking the example of the ongoing Smart Well/Field project in Gabon, the asset is equipped with novel flow sensing equipment, using smart completions that can control interval flows. Real-time data is gathered from the asset, managed and tested continuously for downhole pressure, temperature and actual flow, with direct tie-in to a distributed control system using low cost telemetry. The data is interpreted and evaluated in an integrated production system model for simulation and corrective action. Alternative options are ranked by the asset team, and checked against real economic scenarios in the business systems. Plans are then executed and coordinated with well-system activities. Remote intervention facilitates continuous checks on the status of the smart wells.

Shell has yet to establish the full IT infrastructure, faced with options from over 25 IT vendors. Depending on the asset characteristics, the company must piece together the right vendor coalition for each optimum loop. Key vendors include Schlumberger, Halliburton, Weatherford and WellDynamics (a Smart Well joint venture between Halliburton and Shell), with data management systems developed by Shell Global Services (SGS), and further options from firms such as OSIsoft. Shell's proprietary reservoir modeller, MoReS, is used to visualise materials fluid flow in the reservoir, in order to forecast optimum production performance.

Shell is using its own IT backbone, and also handles system integration. 'In time we hope to move to an industry standard, as we believe it will enable everybody to move ahead much faster,' remarks Kapteijn. Integration standardisation will drive costs down, but there is unlikely to be a standardised industry architecture which will allow 'plug and play' for five or so years. POSC initiatives to date have focussed on subsurface data areas, whereas Smart Fields demand dynamic modelling and continuous updates with so-called vector data.

In 2004, Shell aims to carry out 10 Smart Field projects in lead regions in the Americas and Asia, including the Mars Basin in the Gulf of Mexico, the Iron-Duke and Champion West fields in Brunei, and continuation of a Smart offshore gas production system in Sarawak, Malaysia.

The challenge of integration

As mentioned earlier, integration poses a major challenge. The oil and gas sector lags well behind initiatives in the auto industry, aerospace and even the process industries. 'We still have to build a culture of tight integration,' says Kapteijn. 'No individual vendor or service provider can offer a complete Smart capability, so we will have to form new alliances to deal with the integration issue'.

Benchmarking will be crucial, but there is no absolute level of 'smartness' or real-time optimisation. Shell talks about 'designing the right loop' for asset evaluation, as fundamental understanding is required of the financial and commercial drivers of each asset. 'Evaluating "smartness" will become a core capability for an oil company in order to establish what approach is justified in terms of business value to move an asset to a higher performance level,' he says.

Shell is also looking at 'dashboard' and portal options for encouraging more collaborative environments for asset development. The existing Shell EPone portal is not sufficiently advanced to handle this collaborative function. Smart Fields depends on an integrated team working in a collaborative environment, including information technology (IT), information management (IM), reservoir engineers, geologists, R&D and many others related parties. As more e-enabled and automated systems are introduced, the skills base will also have to change. According to Kapteijn: 'Lower value work in operations will disappear and make way for higher value optimisation work. So a lot of re-skilling will be necessary'

In summary, development of Smart Fields is more about 'capability' than technology. 'Technology is not the limiting factor. Skills development and workflow optimisation are the main challenges,' says Kapteijn. 'Careful design and workflow integration will be required to achieve the best solutions.'

Another exciting trip along the *Hydrocarbon Trail*

***Gill Haben*, EI Education and Training Manager, reports on the latest addition to the Energy Institutes' education/ career website at www.energyinst.org.uk – a 'virtual visit' to ChevronTexaco's Captain oil field in the North Sea.**

Regular readers of *Petroleum Review* will have been following the development of the Institute's interactive education/careers website. The plan is to build a site that is unique, truly informative and FUN, covering all of the curricula as appropriate to the oil, gas and energy industry. The site is being designed for all ages – from primary level to mature learners – and is to follow the full supply chain, providing transparent detail of the amazing range and scope of work in this industry. Accompanying all of this will be a set of 'virtual visits' – of which the Captain trip is the third to be developed. The other two visits are both to Fawley refinery – one has been produced for the 7–11 age range, while the other has been designed for 14- to 16-year-olds and the general public. ExxonMobil sponsored both of these visits.

Work on the education/careers website is being carried out in modular fashion, beginning with the launch in Autumn 2001 of *Discover Petroleum* (DP) (**www.energyinst.org.uk/discover**), and is aimed at 7- to 11-year-olds.

Roving reporters

As mentioned, the third virtual tour that is being developed is a visit to ChevronTexaco's Captain platform – sponsored by the Society of Petroleum Engineers (SPE).

Charles Tracy and David Hawley, our consultant experts, went offshore to film and conduct interviews. The following is Charles' first-hand account of his experience...

'Our aim was to create a virtual visit to an offshore oil platform using 360° panoramas. Students will be able to access these on the web, taking a look from various vantage points. At each stage they can find out more information about points of interest within the panorama.

'In order to create a virtual visit, we had to make a real visit to take the photographs and talk to the crew of a platform. ChevronTexaco kindly offered to give us a tour of the Captain platform in the Moray Firth. As a slightly nervous flyer, I was relieved to discover this was only 45 minutes in the air and, despite some trepidation, I was determined to make the trip as once in a lifetime opportunities like this are rare.

'The helicopter check-in was at 7.30 am – after a 7am rebreather course. There were at least five rookies on our flight, with nerves ranging from resigned calm to outright terror. However, although it was mid-September, it was a beautiful late summer's morning – surely good for helicopter flying and platform visits?

'We watched the refresher video and then struggled into our safety suits. The flight was noisy but very comfortable and unexpectedly enjoyable – unlike an aeroplane. We landed on schedule and were welcomed by Ken Gillan, the Offshore Installation Manager on the well pro-

tection platform (or the OIM on the WPP – Fact 1: everything is referred to by initials!). During the safety presentation we were nourished with bacon rolls and good coffee (Fact 2: the food is excellent).

'We were taken on our tour by Udeni Hewawitharana, a surprisingly youthful production engineer. The next big surprise for me (a rookie, remember!) was how many wells come into the platform. There are 31 wellheads on the Captain – about 30 more than I had assumed. The crude that comes out of them is quite sandy. We saw some straight from a wellhead and it was like frothy caramel that took about ten minutes to settle into something more recognisable.

'This first tour took us to the drilling platform, the chemistry lab and back to the galley. Later, when I was back on land and told old hands that I'd made my offshore visit, their first question was "How was the food?". Of course now I understand that Fact 2 is a key fact of life when you're 30 miles from land for two weeks at a time. The answer is "first class" – a choice of freshly cooked hot meals, salads, fruit and home-baked bread. Indeed, some of our fellow rookies were assessors from Health Promotions to determine whether the Captain's galley should be the first to get a Scottish Healthy Choices Award.

'After lunch, the helicopter was taking people to and from the FPSO (floating production, storage and offloading) vessel about a mile away. The Bristow pilot offered to do a quick circuit of the WPP to let us take some photos from different angles. Fortuitously, there was also a survey vessel in the area so he took a little diversion to sea to get some shots of that too. Only later did I discover the most terrified of my co-rookies was on the flight cursing the "Sassenach snapper". I hope it is some consolation to her that we got some nice pictures that have allowed us to build an "object panorama" for the web. This allows a user to "twizzle" the platform around and view it from every angle as though it were a model on a spinning wheel.

'We had two further tours in the afternoon, taking in the control room and the BLP (bridge linked platform). By now we had got quite used to walking on steel gratings suspended 83 metres above the North Sea. Another reason to be grateful for the good weather!

'At 5 o'clock it was time to head back to the mainland in more beautiful late summer sunshine. Landing is notably more sedate in a helicopter than a jet aircraft – a fact I was reminded of at the end of my aeroplane journey back to Luton. However, perhaps in an attempt to drive home the statistics about flying being the safest per mile way of travelling, my taxi driver was a complete nutcase! It is sobering to think of all the precautions, special suits and courses that we took to be lifted out to a platform and, truly, a car journey is more hazardous.

'Anyway, this turbo-charged taxi ride is not the only reason I haven't fully come back down to Earth since the trip. It was a truly exhilarating day and gave us many snapshots of life offshore – the real sense of challenge and purposeful working; the friendly, calm atmosphere; and the commitment to total safety. Also, rig food is great, helicopters are less scary than Luton taxis and you know you're old when offshore workers look young! We hope to be able to convey some sense of this in the virtual visit.'

Many thanks

I would like to take this opportunity to thank Charles, on behalf of the Energy Institute, for making the trip to Captain. We hope that those of you reading this article will look out for the tour, which will be made available on the website early in 2004. We are confident that readers will be encouraged to sponsor the future development of the *Hydrocarbon Trail*.

Finally, special thanks again to the London and Aberdeen Sections of SPE for sponsoring this virtual visit, especially Pete Naylor and Andrew White.

Equally, I would also like to thank ChevronTexaco for making our third virtual visit a reality. In particular, Ruth Mitchell and her colleagues onshore and offshore, including Ken Gillan, Dawn Murray, Udeni Hewawitharana, Cathy Smith and Ian Ritchie.

And a last thank you to Chris Freeman of Logic and the team at Shell for all their help.

Please feel free to contact me at the Energy Institute if you would like to hear more about the development of the *Hydrocarbon Trail*, or anything relating to our education and training activities. T: +44 (0)20 7467 7135; e: **ghaben@energyinst.org.uk**

A mixed bag

Recent oil and gas discoveries by Petrobras have given Brazil's upstream sector a lift, easing concerns about offshore prospectivity. But international oil companies remain unhappy about the country's investment terms, writes *Ralph Walter*.

On the face of it, Petrobras had an astonishingly successful 2002 – claiming to have discovered 6bn boe, at least half of which it expects to add to proved reserves over the next two or three years. The company is replacing proved reserves, around 11bn boe, at a healthy rate. In order to replace oil production in 2003, it would have to appropriate new reserves of 600m b/y – however, it says that it will add between 1bn and 1.5bn barrels of oil to the company books this year.

The largest new finds are in block BC-60 in the northern part of the prolific Campos Basin. BC-60's two main fields are Jubarte and Cachalote, which hold combined reserves of about 1bn barrels. There are four additional accumulations that are too small to develop on a stand-alone basis, but Petrobras hopes it will be able to tie them into the main development. Although the size of the fields is good news, they are located in deep waters and the oil is heavy – 17° API in Jubarte and 19° API in Cachalote.

Light oil discovery welcomed

In some way of greater encouragement – even though much smaller in size – are new light oil and gas discoveries outside the Campos Basin. Much of the oil discovered offshore Brazil in the last few years has tended to be heavy, viscous and in deep water, putting considerable strain on the technical feasibility and economics of projects. Light oil discoveries are therefore particularly welcome. In addition, exploration success outside the Campos, which accounts for around 80% of national oil production, has raised optimism about exploratory prospects in other basins.

In July, Petrobras announced a discovery, in 1,374 metres of water, in the BES-100 block in the Espírito Santo Basin, to the north of Jubarte. In September, it said reserves totalled an estimated 450mn barrels of 40° API oil, although recoverable volumes were subsequently revised to about 200mn barrels. A large natural gas cap gives the field 'excellent reservoir conditions', according to Petrobras, although no estimates are yet available for gas reserves. The development plan, which envisages start-up within about 30 months, involves installing an early production system that the company hopes will be able to produce 100,000 b/d of oil and between 3mn and 5mn cm/d of gas.

A second light-oil discovery, in the Sergipe/Alagoas Basin, contains an estimated 150mn barrels of 42° API oil and, believes Petrobras, can probably be brought into production within two years.

Meanwhile, Brazil's gas reserves seem set to be transformed by a large discovery in 485 metres of water in the Santos Basin. The gas field, in block BS-400, is thought to contain in the order of 420bn cm of gas. If that proves to be the case, Brazil's gas reserves would almost triple from the present level of 231bn cm.

The discovery's location is fortuitous – at 137 km offshore São Paulo state, it is well placed to serve Brazil's largest market. The discovery also throws into doubt the need to import gas from Bolivia.

Ambitious investment plans

Petrobras' plans for upstream investment remain ambitious. E&P activities dominate the capital expenditure budget. Its five-year strategic plan for 2003–2007 sets aside $18bn for domestic exploration out of a total group budget of $34.3bn.

The company continues to push the boundaries of deepwater exploration through its Procap-3000 research and development programme, which it hopes will enable production in water depths of up to 3,000 metres in the next two to three years. In addition, it is virtually certain that Petrobras will play the leading role in the sixth licensing round, having dominated the five annual rounds that have taken place so far.

Foreign investor disappointments

Nonetheless, despite Petrobras' successes, the experience of international oil companies (IOCs) in exploration offshore Brazil remains undeniably disappointing. When foreign investors flocked to Brazil's newly opened upstream sector in the late 1990s, their yardstick was the 2bn-barrel Roncador field, which Petrobras had discovered in 1996. With a few notable exceptions, discoveries in the intervening seven years have been below par and no operator apart from Petrobras has yet declared an offshore field commercial.

The main gripe among E&P firms is that the fiscal regime is ill-suited to the type of discovery generally being made offshore. Investment terms that may have been acceptable for fields of the size of Roncador are unattractive in the case of smaller developments of heavy oil in deep water – characteristic of many of the last few years' discoveries. Companies are not short of alternatives to Brazil and, unless the government sweetens the terms on offer, interest will decline.

As one senior executive at a major foreign oil company with operations offshore Brazil puts it: 'Consideration to oil quality, size of the accumulation, water depth and the geographic location of any potential hydrocarbons field is needed. Given the limited recent exploration success in Brazil, a re-evaluation of the system, to assure competitive terms and attract investment, will be important.'

A recent Wood Mackenzie report observed that although a reduction in the tax burden might appear to equate to a reduction in state revenues, it could in fact lead to higher revenues because it would encourage the commercialisation of fields that would otherwise remain undeveloped. 'The key,' says Wood Mackenzie, 'is to add flexibility to the fiscal regime, such that development of marginal discoveries can still take place without the government needing to worry about having given away too much should another Roncador be found.'

Alarming signs

However, there were alarming signs this year that the tax burden on oil companies might even increase in Rio de Janeiro state, under whose jurisdiction the bulk of the Campos Basin's fields falls. The state government proposed an 18% tax on oil production at the wellhead, although these plans were suspended, temporarily at least, following protests from oil companies, including Petrobras.

Steve Robertson, an analyst at Douglas-Westwood, a consultancy specialising in deepwater projects, has no doubt about the effect such a decision would have. 'Any extra tax burden on oil production in Brazil will undoubtedly harm the attractiveness of the country to foreign companies.'

New rules stipulating high minimum levels of local content in the supply of equipment and services form another barrier to investment from foreign companies. They fear that, with a reduced pool of companies from which to procure equipment and services, pricing will become less competitive. In addition, there are concerns that if all the projects planned for Brazil's offshore come to fruition, Brazilian industry will be unable to cope with demand, which could lead to unacceptable project delays.

Local content requirements and fiscal terms are said by IOC executives to be among the main reasons for the poor showing in Brazil's fifth licensing round. The relative unattractiveness of the acreage on offer also played a part. It is not easy to compare this year's licensing round with previous ones because the fifth offering was made up of lots of small blocks – previously, a smaller number of much larger blocks have been on offer. But signature bonuses were a fraction of those generated in previous rounds and there were far fewer participants. No foreign majors took new acreage, there were only six winning firms in total and only a few blocks received more than a single bid each.

Reasons for optimism

However, there are also reasons for optimism. First, Petrobras' exploration success will force companies to think again. Second, the sixth licensing round is likely to be much more attractive than the fifth round because it will include acreage held by Petrobras before the open licensing rounds began that has subsequently been relinquished and recycled by the ANP, the oil and gas regulator.

Third, the gulf in discovery success rates between Petrobras and the IOCs is hardly surprising. Petrobras' exploratory drilling rate far outstrips the efforts of all the other E&P companies put together. It remains a fact that exploration density offshore Brazil is far lower than in comparable upstream provinces, such as the Gulf of Mexico. Matthew Shaw, an analyst at Wood Mackenzie, says: 'Although the initial results have been very disappointing, no-one would deny that Brazil's deepwater as a whole is under-explored. There is room for plenty of surprises.'

In addition, there are signs of improvements in the speed at which environmental permits are being awarded. Delays in this process had been threatening some projects, but, according to one executive, 'we have observed steady advancement toward making this process more transparent and functional'.

Production prospects

While new discoveries are needed for sustained long-term production growth, near-term rises in output seem assured from fields already under development. Earlier this year, Shell (80% and operator) announced the landmark start-up of the Bijupirá and Salema fields – the first production brought onstream in the Campos Basin by a privately owned company. Production is expected to rise to a peak of 80,000 b/d of 28–31°API crude and 35m cf/d of gas. Petrobras holds the remaining 20%.

However, additions to production will mainly come from several Petrobras-operated fields (and mostly 100% owned by Petrobras), including Jubarte, Albacora Leste, Marlim Sul, Barracuda, Caratinga and Roncador. Albacora Leste's P-50 floating production unit is expected to start-up in July 2004, reaching peak output of 180,000 b/d in 2007. The shareholdings are Petrobras (90% and operator) and Repsol YPF (10%).

Production is also set to rise at the Marlim Sul field (100% Petrobras). Output averaged 150,000 b/d in 2002, but should climb to a peak of 470,000 b/d in 2009. Barracuda's (100% Petrobras) main production phase is scheduled to begin in January 2005, with peak production of 146,000 b/d expected for 2006. The Caratinga development (100% Petrobras) will enter its main producing phase in the same month, with peak production of up to 127,000 b/d expected in 2006.

The giant Roncador field is expected to be producing at a peak of 500,000 b/d in 2011. It is being developed in four phases and involves the production of oil ranging in quality from 18° API to 31° API.

These developments are expected to result in a steady rise in Petrobras production, which is presently around 1.55mn b/d. By the second half of 2006, the company says it hopes to be producing around 1.95mn b/d, which will mean it will have reached its long-held dream of self-sufficiency in oil and oil products, becoming a net exporter.

Domestic gas production, meanwhile, could also rise dramatically from the present level of 22mn cm/d. Bringing the BS-400 natural gas reserves onstream will take longer, because of the need to build gas pipelines to shore and to develop local markets. But Petrobras believes Brazil's gas market, which consumes about 30mn cm/d, could be absorbing 100mn cm/d or more within the next five to eight years – most of it supplied from domestic resources.

A balanced portfolio

As part of our series of feature articles analysing some of the smaller and intermediate oil and gas companies from around the world – based on information supplied by *Online-Data – we take a closer look at the activities of *Bounty Oil & Gas*.**

Bounty Oil & Gas listed on the Australian Stock Exchange in February 2000. Since then the company has doubled its net acreage holdings; participated in a successful drilling programme in the Woodada gas field; and has farmed out a portion of its interests in its offshore Perth Basin acreage (WA-325-P, WA-327-P and TP/15) in return for the third parties carrying Bounty for the bulk of its share of 2,500 km of 2D seismic, 500 sq km of 3D seismic and two wells.

The company has assembled a balanced portfolio of low risk producing and development projects as well as prospective high risk/high reward offshore exploration permits in western Australia, New Zealand and, more recently, Tanzania.

Strategic operations

Bounty Oil & Gas has its sights set firmly on becoming a significant Australian oil and gas company and, over the past year, has acted strategically to achieve this goal. Due to participate in drilling some high-potential wells over the next year, the company has also attracted significant partners to farm into five of its permits. It has also purchased interests in six permits and been awarded two permits in a competitive bidding round.

In addition, Bounty has expanded its sphere of activity in the international arena by developing an important corporate arrangement with London-based company Aminex. As part of this arrangement, Bounty is participating in drilling the Nyuni and Okuza prospects offshore Tanzania, East Africa.

Australia's Perth Basin

Bounty remains a significant participant in the exploration of the onshore and offshore Perth Basin. In 2003, it participated in an onshore exploration well in permit PL 4 and in one offshore exploration well in permit TP/15. Both wells have provided valuable information for future exploration of the Basin. The next phase of drilling in the company's offshore acreage is scheduled for 1H2004. Bounty holds a 10% interest in PL4 and recently sold a 5% stake in TP/15 to Arc Energy for $5,000,000. A further $5,000,000 bonus will be paid to Bounty at such time as any future production from TP/15 reaches either 5mn barrels of oil or 20PJ of gas.

The company has also improved performance in its Perth Basin production asset – the Woodada gas field – following the completion of the Woodada 19 development well. Production has risen, over 10bn cf of reserves have been upgraded from probable (2P) to proven (1P), and the project has gone from cash flow negative to cash flow positive.

Sydney Basin programme

Bounty has recently farmed out a 1,500 km 2D seismic acquisition programme to UK-based Electro Silica, with work slated to commence in early 2004. Technical work indicates that there is hydrocarbon potential in this permit.

The company has focused its efforts on the large exploration target where the majority of seeps are located. This target has the potential to contain 1.2tn cf of recoverable gas – enough to supply Sydney's gas requirements at the current consumption rate for the next 15 years. Due to its proximity to the east coast's major populated areas, the Sydney Basin gas will have a significant commercial advantage over other projects planned to deliver gas to the region.

New Zealand activities

Bounty also holds an interest in New Zealand's PEP 38215 permit, which covers 13,614 sq km in the Great South Basin off the south coast. The company holds a 33.75% interest and is operator for the joint venture. A technical review of the permit recently completed, including over 6,200 km of specialised seismic reprocessing, full re-interpretation and re-mapping of the seismic and petrophysical analysis of the available well log data.

Unrisked reserves estimates confirm that there is the potential for billions of barrels of recoverable oil within the permit. The review also confirmed the potential for 900bn cf of probable (2P) recoverable gas reserves in the Toroa structure. Technical reports are currently being finalised, and the joint venture is in discussions with potential farm-in third parties to assist in ongoing exploration.

Tanzanian potential

In September 2003 Bounty entered into a strategic relationship with London and Dublin listed company Aminex. As part of this arrangement, Bounty is participating in drilling the Nyuni and Okuza prospects offshore Tanzania, East Africa. By paying 10% of the

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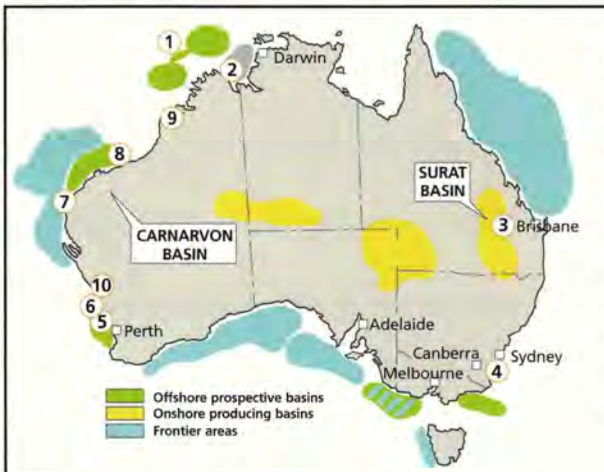
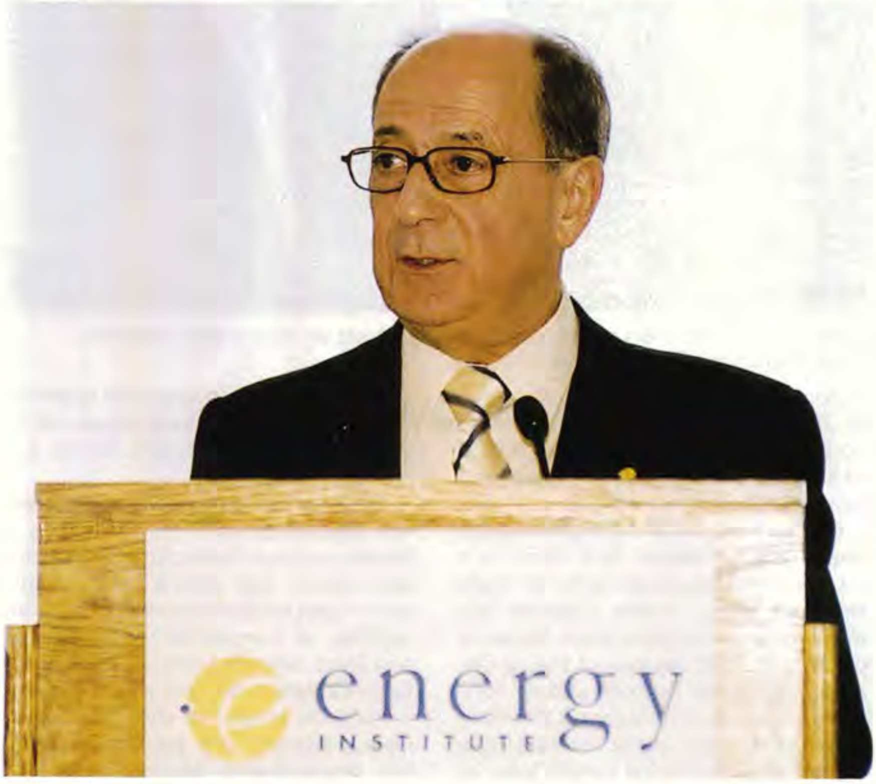


Exploration
1. AC/P 25, 27, 32 – Offshore Vulcan Sub-basin, Ashmore/Cartier Territory
2. WA-324-P – Offshore Bonaparte Basin, WA
3. PL18 & PL40 – Yellowbank and Louise Fields, Onshore Surat Basin, QLD
4. PEP 11 – Offshore Sydney Basin, NSW
5. TP/15 – Offshore Perth Basin, WA
6. WA-325-P & WA-327-P – Offshore North Perth Basin, WA
7. EP412 – Onshore Carnarvon Basin, WA
8. WA-310-P – Offshore North West Shelf, WA
9. EP104 – West Kora, Onshore Canning Basin, WA

Production
10. Woodada Gas Field

Figure 1: Bounty Oil & Gas activities in Australia and New Zealand

Opec and the challenges ahead



***Dr Alvaro Silva Calderón*, Opec Secretary General, outlined the cartel's role and the challenges faced by the oil and gas industry at large when speaking at the EI Autumn Lunch held at Claridges Hotel, London, on 22 October 2003. He said...**

Above: Dr Alvaro Silva Calderón making his speech.
All Autumn Lunch photos by Jim Four

'I should like to talk today about Opec's role and how this equips us to meet the challenges we face in the petroleum industry in the early 21st century. As you may know, the Organization of the Petroleum Exporting Countries, itself, has been around for a long time – since September 1960.

Opec is an international organisation with eleven oil-exporting, developing countries as its Members. These countries exercise permanent sovereignty over their finite petroleum reserves as outlined in United Nations resolutions. They are committed to ensuring that these natural resources are exploited in a sensible and responsible manner.

Principal objectives

The Opec Statute defines our principal objectives. It begins with the coordination and unification of our Member Countries' petroleum policies, the safeguarding of their interests and the securing of a steady income for them from petroleum sales. This is of central importance to us, because petroleum revenue plays a major part in our efforts to develop our economies in a viable and sustainable manner.

The Statute also contains objectives that can be described as outward-looking. It pledges Opec to the achievement of stable oil prices; an efficient, economic and regular supply of petroleum to consuming countries; and fair returns to investors. In other words, Opec's policy is to consider and accommodate the interests of other parties in the industry in its decisions and actions – non-Opec producers, consumers and investors.

In practice, the oil market conditions we seek have three fundamental elements. The first is steady, predictable demand. The second is an absence of disturbances on the supply side, caused by interruptions, shortages and uncertainty. And the third is the maintenance of a fair and stable price range.

In addition to these market-stabilisation activities, Opec has committed itself wholeheartedly to other causes, for which an orderly flow of energy can make a significant difference to the well-being of mankind and the global economy – notably environmental harmony, sustainable development and the eradication of poverty.

The application of energy, in one form or another, is an essential dynamic ingredient of everyday economic activity. Accessing energy can be described as perhaps the most important issue facing mankind, with ramifications which can be economic, political, social, legal or strategic, and a reach which can be local, regional, national or international – or a combination of all of these.

The leading role of oil

Oil is the leading source of commercial energy in the modern world, accounting for around 40% of today's world energy mix. It is a unique commodity, with a combination of attributes which far exceeds that of any other energy source – sufficiency, accessibility, versatility, ease of transport and, in many areas, low costs. These have been complemented by a multitude of practical benefits that can be gained from decades of intensive exploitation and use in the industrial, commercial and domestic fields.

There is every indication that oil will maintain this leading role well into the 21st century. This is in spite of the fact that, over the past decade or so, oil has come under pressure on environmental grounds, particularly in the context of the UN-sponsored climate change negotiations. There have also been longer-standing efforts among some consuming nations to diversify energy sources away from oil, on so-called 'strategic grounds'. However, projections from the reference case of Opec's 'World Energy Model' suggest only a marginal dip to 38% in oil's market share in the period to 2020. In absolute terms, world oil demand is forecast to rise from 76mn b/d in 2000 to 107mn b/d in 2020 – that is, by around 41%.

Gas beneficiary

The chief beneficiary of all of this will be gas. Gas has a more favourable environmental profile among the fossil fuels, and is a reliable and highly efficient source of power generation. It is now relatively low in cost to produce, although still expensive to transport to consumers. Our reference case shows that the use of gas will almost double in the period 2000–2020 and its share in the global energy mix will rise from 23% to 28%; however, this will still be ten percentage points below oil's share. In absolute terms, world gas demand will rise from 42.2mn boe/d in 2000 to 75mn boe/d in 2020 – that is, by around 78%.

All in all, about two-thirds of the world's commercial energy is expected to come from petroleum – oil and gas – in 2020. Opec is well endowed with both hydrocarbons, having almost 80% of the world's proven oil reserves and nearly 50% of its natural gas.

John Mumford OBE, EI Council Member right, greets Dr Alvaro Silva Calderón, centre, and Mrs Silva Calderón, left.

Our proven crude oil reserves total nearly 850bn barrels and there is a reserves-to-production ratio of more than 80 years. These reserves are much more accessible than those in other, high-cost regions of the world. Also, advances in technology continue to make oil a cleaner, safer fuel, so that it can meet increasingly tighter environmental regulations, as well as conforming to the broader demands of sustainable development. Therefore, our Member Countries possess the reserve strength to cope with the forecast rises in demand in the coming decades.

It would seem logical, therefore, for consumers to expect to get most of their oil from Opec's Member Countries.

Groundless fears

However, unjustified fears exist about security of supply and over-dependence on specific regions for crude oil. The reasons for this are an unfortunate mix of fact and fiction. The fact is that the world's oil reserves are concentrated mainly in developing countries, while most customers are located in industrialised nations. The fiction is the belief by some people that developing countries cannot be relied upon to act in a consistent, honourable way in international trade and commerce.

These people refer us back to the events of the 1970s to support their case. But they over-simplify these events, they rarely have a detailed knowledge of them and they overlook the fact that they actually happened 30 years ago and that the world has moved on since then.

These unjustified fears paradoxically can themselves make the oil market a less secure place, by resulting in decisions and actions that contribute to distortions in the market. Running away from realities, as a result of misperceptions and fears, will not solve anyone's problems. Instead, it will only add to them.

I wish to assure you that fears about Opec's integrity are groundless. Opec has demonstrated repeatedly its firm commitment to the three elements I mentioned earlier – security of supply, security of demand and fair, stable prices. The most recent example of this occurred earlier this year, with the hostilities in Iraq. Many people had predicted that this would lead to a sudden steep rise in oil prices and a period of protracted volatility. But this did not occur. Opec ensured that the market was kept well-supplied with oil at all times. Indeed, at around the same time, there were serious unexpected cutbacks in output from two other leading oil producers, and the impact of these on world oil prices was again successfully handled by our organisation, with support from some leading non-Opec producers.

The management of finite resources

The principal issue is how the world chooses to manage its finite oil resources. Opec knows, through both intuition and experience, that it does not operate in a vacuum. If it wants to sell its oil, then it must attract buyers. And it does not attract buyers by scaring them off, or being unreliable. As oil-producing, developing countries, Opec's Members are heavily dependent on a steady flow of income from petroleum sales to help them develop their economies on a sustainable basis. It is in their best interests to ensure that the oil market performs in a stable and orderly fashion at all times. They have nothing to gain from rocking the boat.

Opec realises that its market-stabilisation measures are most effective when they receive widespread support from within the industry. The boundaries between Opec and non-Opec producers, and between producers and consumers, should not be allowed to neutralise Opec's actions. It is a process of interdependence. Producers need consumers and consumers need producers. Companies in-between provide the dynamics, while conferences and seminars create opportunities for constructive dialogue. They all have an important role to play.

Reason, equity and compromise should be the guiding principles when there are diverging interests. For example, people who are concerned about security of supply should acknowledge, at the same time, the need by producers for steady, predictable demand – this is vital, among other things, for the process of making sound investment decisions for the future. Also, while we in Opec would not question the right of sovereign states to devise their domestic fiscal regimes, we believe that, if a government imposes a 70% or 80% tax on petrol, it should at least admit this when oil prices are high and not just stand aside and let oil producers take the blame.

Further, on the question of the deregulation of energy markets, what does this really mean? They are not being totally deregulated, otherwise there would be anarchy and chaos. To what extent, therefore, are they being deregulated and in whose ultimate interest?

We all need to live by rules, but they must be the right rules – fair, balanced, consistent, transparent and the product of consultation among, at least, the most affected parties.

Oil price

Turning to oil prices, these will only be sustainable and useful to the market if they are at levels that balance the contrasting requirements of producers and consumers. Opec has identified a range of \$22–28/b for its reference basket of seven crudes that has won widespread acceptance in the market over the past three years, and it periodically adjusts its production levels to stay within this adopted price band. This has contributed greatly to stability, countering heavy pressure on the market's equilibrium at both ends of the pricing spectrum.

Destabilising factors are not just the result of developments in the market, such as news of unexpected inventory levels or refinery bottlenecks. They can also come about through natural disasters, outbreaks of hostilities or accidents, even when they happen far from oil installations. Whatever the case, they require timely remedial action by Opec, and we seek to provide this, to the best of our ability.

This also has benefits for the longer term, since stability provides a sound base for investment in future production capacity. This has three elements to it. First, it must meet the forecast absolute increase in demand, which I outlined earlier. Secondly, it must see that exhausted reserves are replaced, as and when necessary. And thirdly, it must ensure that oil-producing nations always have sufficient spare capacity available to cope with sudden, unexpected shortages in supply.

Our projections indicate that Opec Member Countries may need to spend nearly \$100bn by 2010 and as much as \$200bn by 2020 to meet the future demand for oil in full. It will require a concerted effort by the industry at large to attract these sums.

Meeting the commitment

I have been privileged to have this opportunity to speak to you about Opec's role in the petroleum industry, as we seek to face the challenges that will arise in the early 21st century. These revolve around ensuring that our Member Countries are able, at all times, to meet the world's steadily growing demand for clean, safe petroleum in a stable, well-ordered market, founded upon transparency, equity and a readiness for constructive dialogue.

We will do everything within our power to meet this commitment.

Business card prize draw winner Robert Quinn of ChevronTexaco receives a bottle of champagne, donated by Claridges, from Mrs Silva Calderón

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estimated A\$15mn drilling costs for these wells, Bounty will earn a 10% interest in the 2,860 sq km Nyuni block – which may hold recoverable reserves of up to 260mn barrels of oil or, if gas is present, 870bn cf. Recoverable reserve estimates at Okuza range up to 100mn barrels of oil or 390bn cf of gas. Aminex, in return, gains exposure to Bounty's Australian and New Zealand portfolio.

The closest exploration well to these prospects – Songo Songo-1 – was a major gas discovery. Located only 20 km southwest of the Nyuni prospect, the Songo Songo gas field contains proved and probable reserves of 590bn cf. The field is due to deliver gas to the capital Dar es Salaam in 2004 through a new, internationally financed, common-user pipeline system that is currently under construction. If gas is discovered in the Nyuni block, pipeline capacity will be made available to the Nyuni co-venturers.

Exploration activity continues to increase in East Africa with a number of larger explorers, including Woodside, Shell and Petrobras, planning exploration programmes in the offshore sector. Bounty's partnership with Aminex in Tanzania allows it to effectively get in on the ground floor in an under-explored area that the company believes has great potential.

Industry first for subsea tie-back

Building on the success of its contributions to the BG-operated Scarab/Saffron project in the West Delta Deep Marine (WDDM) concession offshore Egypt*, *INTEC Engineering* is now providing professional services for the BG-operated Simian/Sienna and Sapphire deepwater projects.

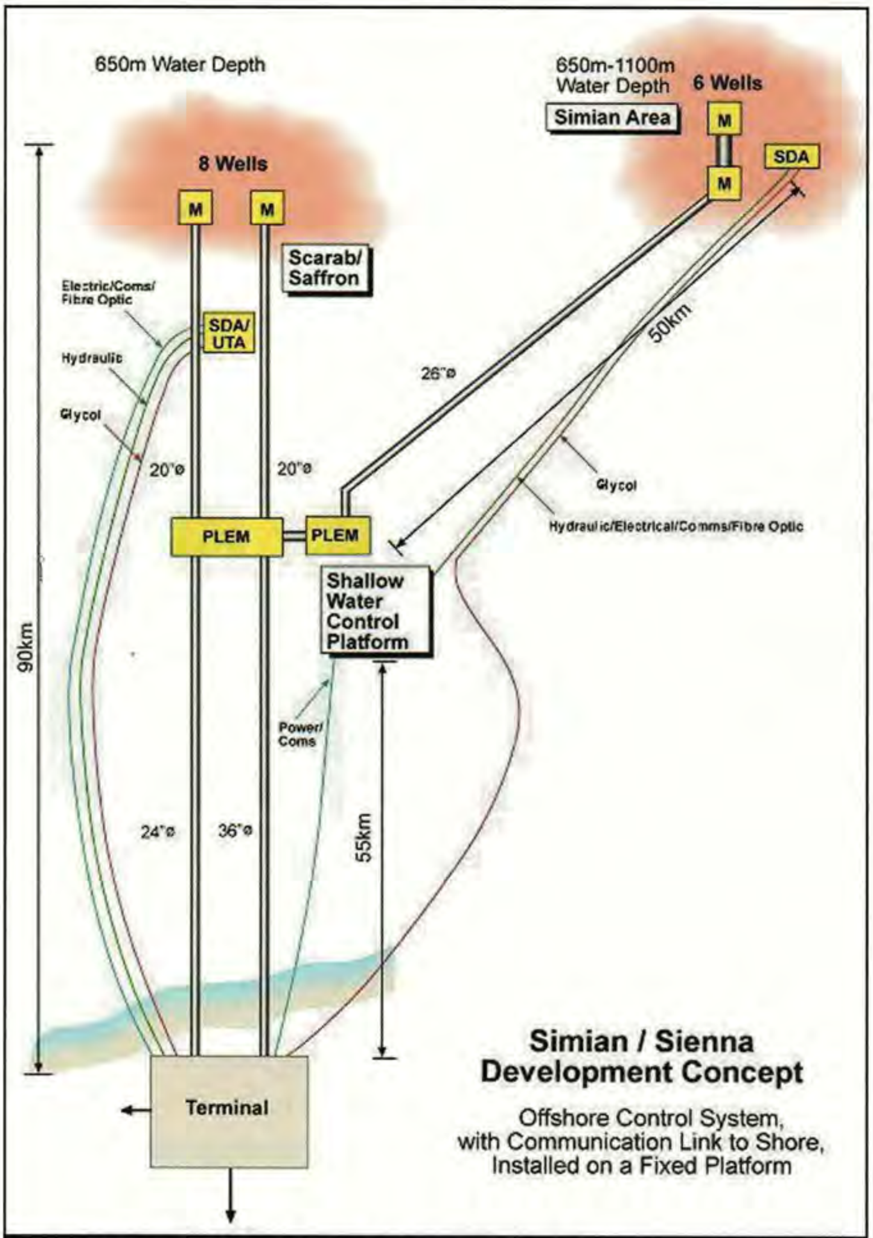


Figure 1: Schematic of Simian/Sienna development concept

The WDDM concession, situated north of the Nile Delta in the Mediterranean Sea, is operated by Burullus Gas Company, a joint venture comprising Egyptian General Petroleum Corporation (EGPC), Egypt's national oil company, BG-Egypt and Petronas.

According to Peter Roberts, INTEC's Managing Director for Europe, Africa and Middle East operations, INTEC is providing a 'seamless transfer of expert technology' from Scarab/Saffron to an integrated management team for Simian/Sienna and Sapphire. 'Through increased integration of key personnel and hands-on engineering from concept selection through the delivery of hydrocarbons, we're helping BG to create a metaphor for industry change. The result is a more flexible working team, providing rapid response and purposeful solutions for complex issues,' he said.

Industry record

As a member of the Burullus Gas Project Management Team (PMT) for the Simian/Sienna and Sapphire projects, INTEC is providing engineering expertise to a project that will install deepwater seabed facilities feeding a large-diameter, 70-mile, long-distance subsea tie-back – setting a new industry record in the process.

Shell's Mensa subsea tie-back currently holds the record at 68 miles. BG first challenged that record last summer with its 56-mile installation of the large-diameter Scarab/Saffron subsea tie-back from wells located in waters up to 2,040 ft to landfall at Idku, Egypt, near Alexandria. The Scarab/Saffron pipeline system began producing gas in March 2003.

The first hydrocarbons from the Simian/Sienna wells located in waters up to 3,600 ft are planned for 3Q2005, with pipelines from the fields tying into the new Scarab/Saffron WDDM subsea system. The Simian/Sienna development will provide feedstock to Egyptian Liquefied Natural Gas' (ELNG) plant at Idku.

The Sapphire field – located west of Scarab Saffron and 46 miles from the Nile Delta shoreline – is a separate development and is scheduled to tie-in to the West Delta Deep system in 2006.

Aiming for the same goal

According to Richard Scarr, BG Project General Manager for the Simian/Sienna and Sapphire developments, the PMT provides an integrated team of BG and

INTEC personnel working toward the same goal – namely 'on-time delivery of a state-of-the-art subsea production system within the scheduled budget'.

'We're building on lessons learned on Scarab/Saffron while utilising INTEC's technical expertise,' he explained, adding that the way in which people are brought together can 'make or break a project'. He noted that, for a project as complex as Simian/Sienna, the company believed that a reduction of interfaces – in an environment where everyone is on a single team – was the best way to yield success for BG and the industry at large.

The PMT is to manage the EPIC (engineering, procurement, installation and commissioning) contract awarded in May 2003. The work package includes all subsea components and the design, fabrication and installation of a new-build unmanned controls platform. Separate from the EPIC contract, but as part of its PMT scope of work, INTEC is also performing detailed flow assurance of the system.

Contracting first

The Simian/Sienna project was contracted through INTEC's UK office, representing the first contract to have been secured independently of INTEC's other global offices. INTEC Engineering (UK) began operations in summer 2001, officially opening its office in Woking in January 2002 to support the needs of customers in Europe, Africa and the Middle East. The company will dedicate approximately 10 people to the Simian/Sienna project over the next three-and-a-half years.

As a member of the PMT, INTEC was charged with the technical tender evaluation of the EPIC contract. Thereafter, INTEC is responsible for technical assurance aspects of the project, including for Simian/Sienna: six subsea christmas trees; two subsea manifolds; one tie-in manifold; a 26-inch diameter export pipeline; a 20-inch diameter in-field pipeline; four 10-inch diameter flowlines from the trees to the manifolds; umbilicals; subsea control system; a four-inch diameter vent pipeline; a four-inch diameter glycol pipeline and controls platform.

The Sapphire development utilises a similar deepwater subsea system, including eight subsea christmas trees.

While system design uses proven technology, there are several challenges associated with the development, according to Graham Taylor, INTEC's Project Manager for Simian/Sienna through the FEED (front-end engineering design) stage. Work on which was completed in July 2002. Some of those challenges include:

- avoidance of hydrates;
- control of chemical injection in required quantities;
- state-of-the-art controls system;
- large-diameter connectors; and
- high production rate trees capable of handling 150mn cf/d of gas.

'Part of the value that INTEC provides the PMT is a complete review of these systems without bias toward any specific equipment supplier. This "independence" increases client confidence that all products on the market, regardless of supplier, are investigated and those best-suited to the project are recommended,' said Taylor.

Another industry first

In general, the Simian/Sienna and Sapphire developments are each comprised of two production hubs, a 26-inch diameter export pipeline for tie-in to the Scarab/Saffron system and a 20-inch diameter in-field pipeline between two manifolds. The development's pipelines are controlled independently of the Scarab/Saffron system, using an electro-hydraulic multiplex system. The controls equipment and a methanol injection unit will be mounted on the controls platform, which will be remotely operated through a combined power and communication umbilical from an onshore facility.

'The controls system represents an industry first because of a combination of length and system complexity,' commented Taylor.

* *See* Petroleum Review, *September 2002*

EI *student chapter*

A new chapter in oil and gas careers

Said Mazaheri was the first Chairman of the IP Student Chapter at Newcastle University, now the EI Student Chapter. Here, he outlines his work with the Chapter and his future plans having recently gained his PhD.

The research that I undertook while part of the School of Marine Science and Technology at Newcastle University covered the hydrodynamic aspects of floating offshore platforms, particularly FPSOs, which are still the most popular form of floating offshore structures. A new approach to the response-based method by using artificial neural networks was developed to simplify the response calculation of the platform as the met-ocean parameters vary. This simplification allows the response-based method to perform quickly whilst processing long-term met-ocean data. This research was financially supported in the form of a scholarship from the Iranian Ministry of Science and Technology, which is gratefully acknowledged.

The Student Chapter at Newcastle University is one of the three Institute student chapters in the UK. It was launched on 6 December 2001 with the aim of giving a head start to students interested in a career in the oil and gas industry. Since then several presentations and visits to industries have been organised by the Newcastle Student Chapter for its members. Among the highlights have been a technical visit to Pipeline Integrity International (PII), as well as the Armstrong lecture plus a technical visit to the Amec yard during construction work for the Bonga project.

I have enjoyed every minute as Chair of the Newcastle Student Chapter, whilst enhancing my knowledge in the field of oil and gas and other sources of energy. Having now obtained my PhD degree I plan keep up my research in the field of offshore platforms, focusing on the future of oil and gas. Also, as a professional in the hydrodynamics sector, I would like to extend my research to sea-based renewable energies such as tidal and wave energy.

Praiseworthy work

Commenting on Said's contribution to the development of the Newcastle Student Chapter, Tom Odell, North East Branch Newcastle University Link Coordinator, says: 'Said is too modest in outlining the work done. He has worked consistently hard in organising visits, meetings, events, etc. At the same time he has undertaken a very demanding academic workload. At all times he has been helpful and full of good humour. Said is a credit to the Chapter, the Energy Institute, Newcastle University, the Iranian Ministry and his country.'

Middle East looks downstream for new gas markets

At present there is far more gas in the Middle East than there are consumers to burn it. As a result, companies are increasingly looking to the downsteam sector to create outlets for the surplus. *Paul McDonald*, Managing Director of Pearl Oil, an oil and energy consultancy based in the UK and Hong Kong, reports.

With foreign oil developments on hold in Iraq and Kuwait and a general lack of enthusiasm for upstream oil deals in Iran, international interest in the Middle East is increasingly focusing on natural gas. However, at present, there is far more gas than there are consumers to burn it. Foreign contractors are therefore heading in large numbers to the region to supply technology designed to convert gas into other products, ranging from feedstocks to polymers.

The Middle East could therefore find itself with a new downstream sector designed to create outlets for its surplus gas. Whether there will be markets for the industry's output is another matter altogether.

Natural gas has been neglected in favour of oil production in most Middle Eastern countries until quite recently – despite the fact that the region contains more than a third of the world's proved reserves, while Iran and Qatar between them account for nearly one-quarter of the world total. Qatar exports gas in the form of LNG as, to a lesser extent, do Oman and Abu Dhabi. The only other gas exporter is Iran, which supplies small volumes by pipeline to Turkey, though Iran itself is a net importer from Turkmenistan.

The lack of a large local market has undoubtedly inhibited development of the region's gas reserves, as have the low prices set by governments. These range generally from $0.75 to $1.30/mn Btu. Several countries have recently tried to open up their gas industries with the help of foreign investors, but have failed to attract sufficient interest. While poor prospects for domestic demand and low transfer prices have been a major disincentive, international companies have also baulked at unattractive upstream contract terms and the lack of a regional pipeline infrastructure that would allow countries with a gas surplus to sell to areas such as Kuwait, where there is a shortage.

All this has led to a search for new gas markets – but attention has shifted away from conventional end-user markets, such as power generation and desalination, to more esoteric uses that involve the conversion of the gas into a range of liquids that can be used by the region's refining and petrochemical industries.

GTL bonanza?

The current favourite among the non-conventional uses for Middle Eastern gas is gas-to-liquids (GTL), which involves the partial oxidation of methane to a synthesis gas of carbon monoxide and hydrogen, and the catalytic conversion of the synthesis gas into liquid hydrocarbon molecules. The first half of the process uses a method dating from the 1920s; the high technology and expense arise from the catalytic conversion of the gas into liquids and waxes. As well as requiring high cost catalysts and pressure vessels, the conversion to liquids is expensive in terms of energy, involving the loss of about one-third of the calorific value of the methane.

The Middle East, however, appears to have methane to spare and is able to supply gas to GTL plants at prices low enough to attract investment proposals. Even so, the economics of some GTL schemes do not look particularly robust given the high cost of the plants and the uncertain outlook for oil product prices. Qatar's 34,000 b/d Oryx plant has a $900mn price-tag, making it more expensive per barrel of liquids' output than many grassroots oil refineries. GTL plants tend to produce higher quality products than conventional oil refineries and are designed to supply premium products at premium prices. The ability of planned Middle Eastern plants to achieve these higher prices is, at the very least, arguable.

Middle Eastern GTL proposals are concentrated in the two countries with the largest reserves – Iran and Qatar (see **Table 1**). These countries also have another important feature in common – they share a major gas structure known as the 'Khuff', which provides each country with its most important non-associated gas field. In the case of Qatar, this is the 250tn cf North field, while in Iran it is the South Pars field where proved reserves are put at 300tn cf. The two countries, however, have failed to agree a boundary for their respective fields.

The inability to divide the spoils of the Khuff formation appears to be encouraging both countries to develop what they see as their own reserves as rapidly as possible in an attempt by each to pre-empt the capture of reserves by the other. In the absence of sufficient LNG and other conventional gas outlets, GTL seems to provide an attractive and potentially large new market – hence the proposals for up to eight new liquids plants (see **Table 2**).

GTL also fits into both countries' plans to develop their downstream oil and petrochemical sectors. Qatar's petrochemical industry is dated from the establishment of the Qatar Fertilizer Company (Qafco) in 1969 and has included several plants designed to turn natural gas into fuels and petrochemicals, including methanol and its derivatives. Iran also started with fertilizer production, some six years earlier than Qatar, and is now proposing to build a range of gas-using facilities. Both countries are attracted by the prospect of supplying markets in Asia, especially China, with petrochemicals and liquids produced from cheap feedstocks.

GTL is not the only process being proposed to convert methane into bigger molecules. Other export routes being touted are methanol and olefins, such as ethylene. Several Middle Eastern countries with untapped gas reserves are being urged to use their feedstock advantage to the full and to export ever-increasing volumes of gas-based liquids and petrochemicals, thus turning cheap gas into a range of high-priced liquids and other products.

Country	Reserves (tn cf)	Production	Consumption (bn cf/d)	Net trade
Iran	812	6.2	6.6	(0.4)
Qatar	509	2.8	1.0	1.8
Saudi Arabia	225	5.5	5.5	—
UAE	212	4.4	3.8	0.6
Others	222	3.9	3.0	0.9
Total	1,980	22.8	19.9	2.9

Source: BP Statistical Review of World Energy, 2003
Note: totals rounded

Table 1: Middle East gas balances, 2002

Company	Plant size (b/d)
Iran	
NPC; Sasol	34,000–110,000
NPC; NIOC; Shell	70,000
NPC; NIOC; Statoil; Mossgas	60,000–80,000
Total	**164,000–260,000**
Qatar	
QP; ConocoPhillips	50,000–300,000
QP; ExxonMobil	110,000
QP; Marathon	80,000–120,000
QP; Sasol	34,000
QP; Shell	70,000–140,000
Total	**344,000–704,000**

Notes: NPC – National Petrochemical Company; NIOC – National Iranian Oil Company; QP – Qatar Petroleum. Volumes are approximate

Table 2: Middle East GTL plans

Premium prices for premium fuels?

While the region's producers are well able to ensure that gas is supplied cheaply, they may find themselves rather less able to obtain the premium prices they presume their GTL liquids command. GTL plants certainly produce high quality, low sulphur, nitrogen-free liquids. GTL diesel not only meets international specifications for ultra-low sulphur diesel, it also has a cetane number of around 70, making it an ideal blendstock for refiners. Such qualities, however, are of little use in the Middle East, where diesel is not required to meet the tight specifications adopted in most of the OECD. To gain the higher price, the GTL diesel must be exported, thereby incurring a freight penalty that could offset part of the expected premium.

Diesel is expected to make up about 75% of GTL output, leaving the remainder mainly as naphtha. This, too, is more or less sulphur-free – but here the lack of sulphur has little commercial advantage in the transport fuels market since GTL naphtha is paraffinic and therefore too low in octane for gasoline blending. While this makes it an ideal feedstock for petrochemical crackers, sulphur-free naphtha has few advantages in the production of olefins. Moreover, GTL naphtha may well find itself in competition with subsidised LPG as a cracker feedstock in parts of the Middle East.

Added to the difficulties over pricing are further uncertainties concerning the GTL technology itself. Existing plants are largely demonstration plants – those planned for the Middle East are in many cases an order of magnitude larger (see **Table 2**). At present 10,000 b/d constitutes a 'large' GTL plant. Economies of scale, however, tend to come in around 70,000 b/d or even higher, depending on the process chosen. The first plant to be agreed in the region is a 34,000 b/d venture between Qatar Petroleum (QP) and Sasol. Shell has now signed heads of agreement with QP for the Emirate's second GTL unit, at 70,000 b/d.

There are risks with sizing-up the technology to convert synthesis gas into liquids. The joint QP/Shell plant is likely to be the largest in the world when commissioned in 2008–2009. Qatar and Iran between them are studying plants with individual capacities of up to 300,000 b/d. Some may not be built, while others may be delayed in order to allow further proving of the liquids' conversion technology. Project financing is unlikely to be easy without performance guarantees covering the technology, and the cost of the individual units may well exceed that of similar sized grassroots refineries, which are also capable of producing a more flexible product slate.

All Middle Eastern GTL plants are likely to require the gas to be delivered to the plant at low prices and this could have implications for the upstream developments themselves. Unless more international oil and gas companies are willing to take on the technological and market risks of GTL plants, some gas developments may not take place at all, especially if there are unusually high political risks associated with the Middle Eastern gas producer in question.

Looking ahead

Despite all these problems, the Middle East is unlikely to see an end to future proposals to turn gas into liquids. Qatar appears determined to become the region's – if not the world's – GTL capital. It is likely to be able to improve the economics of its GTL programme by recovering some NGLs directly from the gas.

Iran, on the other hand, may not be quite so successful. The Iranians need to find new uses for South Pars gas following problems with an over-ambitious LNG export programme. GTL has been selected as an option, but disagreements over upstream contract terms may also delay the GTL programme.

Qatar and Iran may not be the only Middle Eastern countries to try and go down the GTL route. Saudi Arabia is trying to bring a number of major gas projects onstream. Power generation is likely to account for large volumes of any methane produced, but Saudi gas projects threaten to swamp not only the Kingdom's gas market but also those of its neighbours. The Saudi petrochemical industry is based principally on cheap ethane, propane and butane, leaving few outlets outside methanol for any surplus methane. This could make GTL the fallback option.

Iraq may also look at GTL, since it will probably need to find markets to replace its planned exports of gas to Turkey. As long as the region's governments are prepared to make gas available at low prices, the Middle East is likely to go on attracting proposals to turn it into expensive liquids.

NW Europe – life in the old province yet

***Tony Doré*, Vice President Global Exploration, Americas, Statoil, and Chairman of the 6th Petroleum Geology Conference (PGC) recently held at the Queen Elizabeth II Centre in Westminster, provides a brief overview of the event, which was jointly organised by the Energy Institute, the Geological Society and PESGB. Once again, the event was a forum for companies to reveal key data previously held confidential while some of the best thinkers in the geoscience community chose it to unveil their newest ideas.**

As Chairman I must admit that I'm still feeling a nice warm glow about the whole conference – it went smoothly, the quality of the speakers and presentations was high, and people went away pleased and stimulated by what they had seen and heard.

However, it didn't always look this promising and there were many reasons why the event might never have got off the ground. Early doubters had commented on the decline in NW European exploration, asking whether there should even be another conference. Countering this, others pointed out that, even without exploration, there is still a thriving community of geoscientists concerned with maximizing recovery from our offshore fields. Furthermore, there is an unparalled database to analyse, and a long tradition of export and import of ideas between NW Europe and other petroleum provinces worldwide.

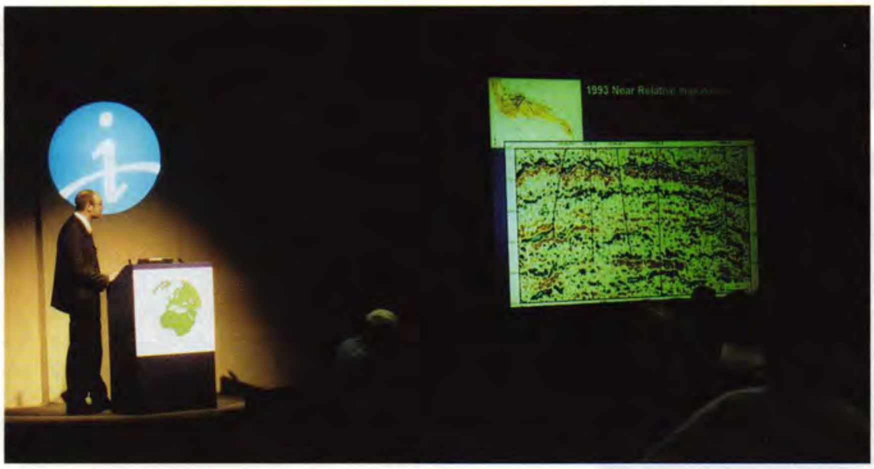
So, armed with these ideas, the PGC Technical Committee broadened the programme to include retrospective views of exploration, in order to emphasize reservoir geology and new technology, and to address the 'global perspectives' of the title. Another worry was the proximity in time to the AAPG Convention, held a couple of weeks earlier in Barcelona and a potential competitor for the same customer base. As it was, the programmes were kept complementary and both conferences were well attended, successful events – exactly as anybody with an interest in a thriving geoscience community would want.

Attended by approximately 950 delegates, the conference was opened by Sir Mark Moody-Stuart, President of the Geological Society, and Stephen Timms MP, UK Minister of State for Energy, E-Commerce and Postal Service, at the 'Icebreaker' session on Monday 6 October. Each succeeding day was introduced by a plenary session featuring senior industry figures taking on major generic issues of both NW European and global significance. Delegates were then treated to up to four parallel sessions ranging from detailed reservoir geology to frontier exploration, emphasizing state-of-the-art technology.

3D visions

Of special note was the 3D Visions session, in which a 'visionarium' environment was created in the conference centre and many of the presentations were in actual 3D. It was a novel experience being presented to by both a speaker and a 'pilot', the latter steering you through seismic sections, along migration pathways and even through the pores of rocks. One or two less resilient souls were seen reeling for the doorways, no doubt for a breath of fresh air and to get their sea-legs back!

The Core Workshop was also very well received. About 40 separate cores, comprising several kilometres of rock, were selected in order to provide an optimum geographical and stratigraphical spread, and to add substance to the papers in the main programme. Naturally, the beautifully smelly and oil-drenched cores from the Buzzard field attracted a lot of attention. This recently discovered giant oil field on the UKCS, and the recent rejuvenation of the UK's oldest oil field (Argyll, now named Ardmore) through modern drilling and completion technology, formed a poignant backdrop to the conference. Both were described in



detail, and both seemed to show that there's life in the old province yet.

Bringing out the best

My overriding impression after the conference is that this four- to five-yearly event, with its strong emphasis on technical quality, really brings out the best in the industry and its associated geoscientists. Companies seem to choose this event to reveal key data previously held confidential, while some of the best thinkers in the geoscience community choose it to unveil their newest ideas. This may be why the proceedings' volumes – almost universally referred to as the 'Barbican' volumes in deference to previous venues – have become such standard works in NW European exploration and production.

Things look promising for the timely production of the latest set of proceedings. After a superhuman, tree-shaking exercise from the convenors, we now have more than 130 papers in hand and

going through the review process. We expect to bring the proceedings out as a two-volume set, together with an interactive DVD containing links between text, core photos and movie files. ●

To purchase copies of the proceedings, please contact e: sales@geolsoc.org.uk

Main photo: Delegates at the 3D display. This page (clockwise from top): Stephen Timms, MP (left) and Sir Mark Moody-Stuart (right), who opened the conference, are talking to Tony Doré, Conference Chairman; the exhibition enabled delegates to test new products; the conference hall; one of the four parallel sessions; experiencing new equipment; a feast for geological eyes with many rock samples on display.
All photos: Jim Four

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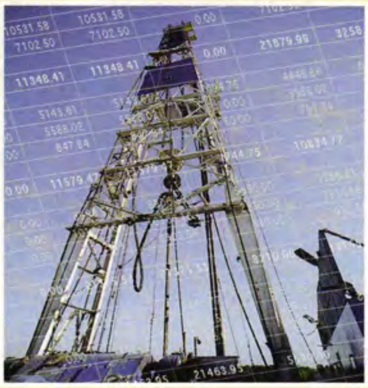

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Valero bases its maintenance planning on SAP systems

Valero, with a refining capacity now approaching 2mn b/d, has grown from a one-refinery company to one operating 13 refineries in the last six years with all the challenges of integration, planning and reporting involved. *Rick Griffin*, Director of Refining Operations, and *Hal Zesch*, Chief Information Officer, recently told *Petroleum Review*'s Editor *Chris Skrebowski* how they had met the integration challenge and how SAP systems had helped in the task.

Q What was the main challenge facing Valero as it expanded its operations?

A The first requirement was for Valero to have a consistent view of its operations as the company rapidly grew from operating one refinery to operating 13, explained Hal Zesch. Only with a consistent view is it possible to define key performance indicators and for management to start to benchmark between locations, he explained. One of the major challenges in integrating the various units had been the fact that each refinery had its own culture, traditions and approaches, which was why common solutions were needed to achieve group synergies. He noted that Valero had moved to using SAP in 1997 but explained that its effectiveness largely depended on how well the system was implemented. If it was done well it became a common language for the employees in their day-to-day tasks.

Q What in particular did SAP offer to Valero?

A Rick Griffin explained that as Valero grew from its San Antonio base to a company operating refineries from Canada to the US Gulf Coast and to the US West Coast they had developed a system of sharing people between locations. Manpower requirements varied, requiring greater numbers at the point when a new refinery was being integrated into the group or during maintenance shutdowns. By sharing people between locations you dealt with the manpower requirement, spread expertise and helped to develop a collective approach. The flexibility of SAP and the way that it can be tailored to meet individual requirements means that operatives with experience of it can move productively between locations, applying their skills with only minimal familiarisation training. Griffin noted that SAP offered almost more flexibility than was required, although this offered some degree of future proofing against requirements not yet thought of. His view was that SAP's business flowchart is still a unique solution that allows full control and monitoring of the business process.

He noted that even with refineries that were completely different there were common themes — these could be incorporated in a productive way, making use of SAP's ability to capture data in real time. Futhermore the various SAP systems had now become core to Valero's business, with over 80% of all staff able to use and make use of aspects of the system in their everyday work. Even their training on the system was done using SAP features.

Q Did you run into any major snags or problems?

A According to Griffin the importance of communication cannot be overestimated. People and locations have their own systems and to effect productive change they must be persuaded of the value of change and must buy into the new systems and new ways of operating. This change management is neither easy nor quick, and requires appropriate training for both the managers and those they are managing. Standardising all locations onto a common SAP platform had been a powerful coordinating force.

Q How has it worked out so far?

A The company had learned a lot and one of the keys to successful implementation was to leverage the skills of the people in the various locations. It was important to recognise that their primary skills were functional and that operating computer systems was secondary in the sense that personnel would only develop computer skills if it made their work easier and more effective, said Griffin. He noted that over 80% of the total staff now had SAP skills that they were using in the course of their daily work.

Q How do you see things developing in the future?

A Both Zesch and Griffin felt that they now had a system which allowed effective management of the existing assets and the ready integration of any additional ones. By making use of super users, who move between sites, they were able to leverage local knowledge but also leave knowledge on site in a form where it can readily be applied.

In terms of new assets they explained that this had become a set process rather like a military operation. The most recent acquisition had been concluded in May and by the beginning of July 100% of the cash flow was on the new systems. They made the point that there were many ways to do it wrong and that it was important to recognise that the system was an aid and support for the business — it was not a system project. Their view was that, although additional asset presented a challenge to integrate it into the overall system with complete management support, they had now reached the point where it could be regarded as routine.

They cited a steam leak as an example of how integrated the system had now become in terms of day-to-day operations. This would be logged and the information passed to the planner, who would locate the required parts and do the timing and costing of the work. As all aspects would be recorded on the SAP system, which allowed work to be easily tracked and a repair history to be developed for subsequent use and analysis.

Q How reliable has the system been?

A Zesch explained that the company operated twin servers with the database mirrored onto both to ensure consistent availability. The success of this is testified to by the fact that they have had 99.9% uptime according to Zesch.

Q How do you see the US refining scene developing?

A According to Griffin the outlook is improving, with the US economy reviving and the world refining scene rather more balanced. There was a clear consolidation trend in terms of environmental regulation. He also noted that the well established trend was to get more production from existing sites recording that Valero last built a greenfield refinery in the 1980s.

Getting connected

The most popular pipe connection method throughout the oil and gas industry is the ANSI flange, but despite its popularity it is a technology that has not been developed to meet today's operational demands, writes *Sjur Lassensen*, Vector International's Technical Director–Norway. A tendency to utilise the tried-and-tested ANSI flange and lack of knowledge regarding modern pipe connection alternatives is seeing industry failing to capitalize on the significant benefits high performance compact connectors offer.

ANSI problems

ANSI flanges create a seal using bolting to compress a gasket between two seal faces, but to apply the forces required to compress a gasket sufficiently can lead to the flange being bent or distorted. This is resolved by using large bolts so the required leverage can be applied without distorting the flange. Bigger bolts means bigger nuts, which means bigger flange. Combined, this means significant size and weight – making them particularly unsuitable for application in confined spaces where clearance can be a problem and cumbersome, and therefore time consuming, should piping need modifying or upgrading.

The biggest problem, however, is that the traditional flange is not guaranteed leak-free. A standard flange is a dynamic connection and there is always a small amount of movement between the flange faces. Such movement affects the functionality of the gasket that will lead to leakage.

In contrast, a compact flange is not only smaller and lighter than the traditional flange, but is guaranteed not to leak. A leak-free seal is achieved as the bolt pre-load is transferred directly through the mating flange faces, not a gasket. Once pressure-tight after assembly a static face-to-face connection is created which is unaffected by the internal pressure or the external loads acting on the flange, hence it cannot leak. Moreover, with lower pressures needed, both the size and number of the bolts can be reduced, ultimately providing a smaller, lighter-weight connection that is far easier and quicker to install.

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By eliminating leakage compact flanges like Vector's provide significant costs savings through waste reduction and decreased maintenance requirements, and improve health and safety.

Future growth

With issues of assured joint integrity and avoiding unnecessary emissions more important than ever for the industry, compact pipe connection technology has a valuable contribution to make in reducing leaks. The technology has proven to be a more reliable connection method than the ANSI flange, yet is still often relegated to where pipe connections are critical due to operators' inclination to use the familiar ANSI flange. It is time for the petrochemical industry to start recognising the numerous benefits on offer – there is no doubt that compact pipe flanges are the better choice for today and tomorrow.

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Improved portable gasoline analysis now available

The Grabner IROX 2000 from Sartec is a new compact, robust and user-friendly mid-FTIR spectrometer for the automatic measurement of the concentration of the most important components of gasoline.

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A large number of country-specific calibration samples are stored and outlier fuels can be easily added through the callibration menu using the integral display/keyboard. The portability and vehicle battery options make the unit ideal for on-site field applications.

The heart of the instrument is an extremely compact mid-FTIR spectrometer. Fully automatic optical realignment during warm-up ensures high stability even after long use or transportation, claims the manufacturer.

Instead of a few filter-lines, the complete absorption spectrum is measured. This is said to provide complete information on the substance present in the gasoline, eliminating variations of the baseline and minimising interference.

The instrument measures a wide range of parameters and meets ASTM D5845, ASTM D6277 and EN238 Standards.

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- first rate communications skills, both oral and written, including the ability to present a rational argument with authority

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- representation for the oil industry to government, NGOs, media and the public
- direction and co-ordination of a small, professional secretariat supported by a number of specialist committees and work groups

Apply in writing with full career and current salary details to:
The President
UK Petroleum Industry Association
9 Kingsway
London WC2B 6XF

Or by email: president@ukpia.com

Please mark the envelope or email "Private & Confidential" and send it to arrive no later than 15th January 2004

A full job description is available on our web site www.ukpia.com under "Publications"

OXFORD INSTITUTE FOR ENERGY STUDIES

GAS RESEARCH PROGRAMME

The Oxford Institute for Energy Studies is seeking research staff at junior and senior levels to work in its newly created Natural Gas Research Programme which will focus on issues of: pipeline and liquefied natural gas markets and economics, liberalisation, competition and regulation, investment issues, security of supply, and producer/consumer dialogue. Enthusiasm for the subject and ability to write well and clearly in English are essential. Priority will be given to those with research experience and some knowledge of the subject (and of the energy industries in general), and those with relevant language capabilities. Salary according to academic scales.

The closing date for applications is 9th January 2004.

Please apply in the first instance to Lavinia Brandon by E-mail: lavinia.brandon@oxfordenergy.org or by post to Oxford Institute for Energy Studies, 57 Woodstock Road, Oxford, OX2 6FA.

Membership News

FELLOWS

Christopher Boocock CEng FEI, Kodak
Paul Holmes CEng FEI, Huntsman Tioxide
Edmund Bartholomew Stevens CEng FEI, Max Fordham LLP

MEMBERS

Andrew Thrower CEng MEI, Watkins Payne Partnership
Robert Docherty CEng MEI, Flamerisk
Peter Barrett MEI, Johnson Controls
Stephen John Barker CEng MEI
Daniel Kunaver CEng MEI, Marathon Oil UK
Gary Whyte CEng MEI
Ashley Barnett CEng MEI, Hull City Council
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Felix Ampofo CEng MEI, South Bank University
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Herbert John Brown CEng MEI, Dupont (UK)
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Marion Ruth Beaver CEng MEI
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Michael Lyons CEng MEI, Cork City Council

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Andrew Carter IEng AMEI, AVC Consultant
Stephen Connor IEng AMEI

GRADUATE MEMBERS

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Charles Ian Dixon GradEI, Imperial College
Francois Pierrel GradEI, Consultant
Alan Owen GradEI, Robert Gordon University
Arfakhshand Ali Qazalbash GradEI
Nikolaos Soulopoulos GradEI, Imperial College
Omer Shuja Ahmad GradEI
Rajat Gupta GradEI

STUDENTS

Claire Louise Briggs, Newcastle University
Kelly Suzanne Lee, Newcastle University
Thomas Cullingford, Newcastle University
Claire Swift, Newcastle University
Karleen Matcher, Newcastle University
Caroline Fox, Cardiff University
Shreyas Rajan, Sheffield University
Franchesca Pironti, University of Sheffield
Jonathan Williams, University of Strathclyde

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Neil Ronaldson, North Warwickshire Council
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Graeme Low, Islington Council
William David Brand, Energy Institute
Rohit Narayan, HCL Tech Europe
Michael Austell, $INCO_2$ UK
Mark Justin David Purdy, IHS Energy
Colin Grenville, Powergen UK

DECEASED

Mr Noel C Crighton CEng MEI

Branch News

LONDON

Contact:	*Ian Robinson, e: IRobin1040@aol.com T: +44 (0)1932 783774*
9 December:	18.00: *Flammability – Regulation of Flammable Materials*, Dr Alan Brown, HSE

Discussion Groups

ENERGY, ECONOMICS, ENVIRONMENT

Fusion – joker or ace of trumps in the energy pack?

Wednesday 14 January 2003
17.00 for 17.30 – 19.00 *Refreshments Provided*

Speaker: **Professor Sir Christopher Llewellyn Smith** FRS – Director, UKAEA Culham Division

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

Contact: **Laura Viscione Tel: +44 (0)20 7467 7174**
Fax: +44 (0)20 7580 2230 e: lviscione@energyinst.org.uk
www.energyinst.org.uk

COMING UP IN 2004

LNG Vehicles

Wednesday 3 March 2004
Speaker: **Roy James** – Chive Ltd

Road Transport Fuels

Wednesday 7 April 2004
Speaker: **John Mumford** OBE – BP Oil UK Ltd

Contact: **Laura Viscione Tel: +44 (0)20 7467 7174**
Fax: +44 (0)20 7580 2230 e: lviscione@energyinst.org.uk
www.energyinst.org.uk

STOP PRESS...STOP PRESS...STOP PRESS
From January 2004, Membership News will appear in *Petroleum Review* as a separate supplement.

IP WEEK 2004
16 – 19 FEBRUARY
LONDON

IP ANNUAL LUNCH

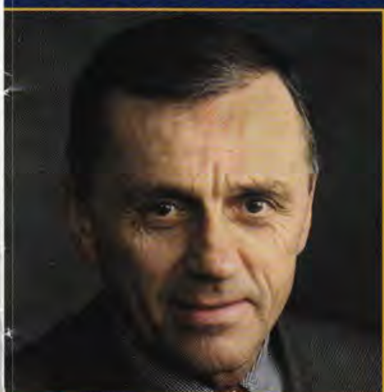
Tuesday 17 February 2004, 12.30 – 14.45 at the Dorchester Hotel, Park Lane, London

The IP Annual Lunch, held in the elegant surroundings of the Dorchester Hotel, provides an excellent opportunity to hear an international leading figure speak about the key issues affecting the petroleum industry today.

Guest of Honour and Speaker

Inge Ketil Hansen

Acting President and Chief Executive Officer, Statoil



Inge Ketil Hansen was appointed Acting Chief Executive in September 2003.

Hansen became Chief Financial Officer and Executive Vice President for Statoil's Corporate Centre and Services in March 2000. He joined Statoil from Orkla Finans where he was Managing Director.

After graduating from the Norwegian School of Economics and Business Administration in 1970 with an MSc in Business Economics, he joined the Research Institute for the Pulp & Paper Industry, and held a series of posts at Jiffy from 1973-80.

Hansen has also been President of Nor Independent Leasing and a General Manager with Bergen Bank/Den norske Bank.

Hansen is also a member of the board of directors of the Norwegian School of Management.

For more information on this and other IP Week 2004 events, please visit:

www.ipweek.co.uk

TICKET APPLICATION FORM

energy INSTITUTE

Please photocopy this page and send completed form to the Events Department, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK F: +44 (0)20 7580 2230

I wish to order .... ticket(s) @ £149.00 + 17.5% VAT (£26.08) each = Total £ ....

Title: ..... Forename: .... Surname: ....

EI Membership No: .... Company: ....

Address: ....

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I will pay the total amount by:

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

☐ Visa ☐ MasterCard ☐ Euro Card ☐ Diners Club ☐ American Express

Card Number: ☐☐☐☐ ☐☐☐☐ ☐☐☐☐☐☐☐☐

Valid from: ☐☐ / ☐☐ Expiry: ☐☐ / ☐☐

Credit card holder's name and address:

Forename: .... Surname: ....

Billing Address: ....

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Postcode: .... Country: ....

Signature: .... Date: ....

Data Protection Act

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

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

Terms & Conditions:

- Tickets can be purchased by Members and Non-Members of the Energy Institute (EI)
- The cost of one ticket is £149 + VAT (£26.08) Total - £175.08 and includes pre-lunch drinks and wine. VAT is payable by UK and overseas purchasers. Liqueurs are not included in the ticket price. Full payment must be received before tickets can be guaranteed.
- Seating arrangements will be organised by the EI, bearing in mind guests' wishes. Companies or individuals wishing to share tables must state this when completing the application form, as changes cannot be made after tickets have been allocated.
- Special dietary requirement will be accommodated if notified to the EI by 6 February. An additional charge may be incurred.
- Guests' names should be submitted in writing to the EI by Wednesday 28 January 2004 for inclusion in the printed guest list. Name changes or additions submitted after this date cannot be included in the printed guest list.
- This event is included in the IP Week Pass, a well as the Tuesday morning and Tuesday afternoon passes.
- If you cancel the order, a refund, less a 20% administration charge of the total monies paid will be made provided notice of cancellation is received in writing on or before 5 January 2004. No refunds will be paid or invoices cancelled after this date.
- Dress is lounge suit.
- An application for tickets indicates your acceptance of the terms and conditions listed above. Upon the EI receiving your booking form (by fax, post or email) you become liable for full payment of the fee and you undertake to adhere to the terms and conditions as specified. This is not a tax invoice.

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IP WEEK 2004
16 – 19 FEBRUARY
LONDON

in association with

Petroleum *review*

publishers of IP Week 2004 daily

Energy Intelligence

WELCOME TO 90TH IP WEEK!

IP Week is the focal point in Europe each year for leading oil and gas industry professionals. It offers an intensive round of conferences, seminars, industry and trade association events, oil industry's largest Annual Dinner and Annual Lunch.

This is the first IP Week staged by the new Energy Institute, a professional body created in 2003 by the merger of the Institute of Petroleum and the Institute of Energy formed to support individuals and organisations across the energy industry.

The week will include conferences focusing on:

- Energy price
- Refining
- Gas
- Exploration
- Oil and gas in FSU
- Transportation security
- European downstream issues
- Upstream

Selected IP Week 2004 events are organised in partnership with / sponsored by:

International Institution of gas Engineers & Managers · WOOD MACKENZIE · Landmark A Halliburton Company · New York Mercantile Exchange · europia · Ashurst Morris Crisp · CARGO SECURITY INTERNATIONAL

IP ANNUAL LUNCH

Tuesday 17 February, Dorchester Hotel, London

The Annual Lunch provides a unique opportunity to hear one of the world's senior figures in today's oil and gas industry discuss the key issues facing the industry in the context of the changing economic, social and political environment.

Guest of Honour and Speaker:

Inge Ketil Hansen, Acting President and Chief Executive Officer, Statoil

IP ANNUAL DINNER

Wednesday 18 February, Grosvenor House Hotel, London

The 90th Annual Dinner is a unique event in the international petroleum industry, which brings together over 1000 of its leading figures, and provides an opportunity to meet with old friends and acquaintances.

Guest of Honour and Speaker:

John Simpson CBE, BBC World Affairs Editor

EXHIBITION

16 – 19 February, London

Maximise on business and promotional opportunities connected with IP Week 2004 by participating in the oil and gas information services exhibition. The exhibition will be held alongside 2004 events.

All conference and seminar refreshment breaks will be held in the exhibition hall, enabling exhibitors to take full advantage of networking opportunities offered by IP Week. Each conference and seminar session will attract a number of senior oil and gas executives.

Space is very limited so book your stand now!

THE REST OF THE INDUSTRY WILL BE THERE, PLAN NOW TO JOIN US IN LONDON !

For more information on IP Week 2004, contact the Events Department at the Energy Institute:

T: +44 (0)20 7467 7100 e: events@energyinst.org.uk or visit: www.ipweek.co.uk