Petroleum review

DECEMBER 2002

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New Zealand

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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: Aotearoa – the land of the long white cloud. Global interest in New Zealand E&P prospects continues to grow. See page 18.

Scene: Marlborough Sounds, South Island, New Zealand

Photo: Emma Parsons

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INSIDE BACK COVER – IP ANNUAL LUNCH 2003 BOOKING FORM

ROUNDUP From the Editor

Love, betrayal and Iraq's production potential

For the international oil and gas industry the last month has been little short of traumatic. Demand remained sluggish but production, according to the latest (November) *Oil Market Report* from the International Energy Agency (IEA), rose by 1.25mn b/d to 78.3mn b/d. Opec supply rose by 760,000 b/d, with 570,000 b/d of this coming from Iraq. Non-Opec supply rose by 450,000 b/d, nearly 300,000 b/d of which was in Norway as post-maintenance volumes built back to 'normal' levels.

In the face of this 'excess' supply, prices fell by $4–5/b, completely eroding the so-called war premium and apparently ignoring the fact that US crude and distillate stocks are now below 'normal' levels. Across the OECD stocks are now below year earlier levels, with forward demand cover at 53 days – three days less than in 2001.

Third quarter results were generally weak, with most companies reporting large falls in earnings. However, the analysts managed once again to replace rational analysis with low farce as they very publicly declared that they no longer loved BP but now loved Shell. The resemblance to who is 'in' and who is 'out' in teenage girl gangs is now overwhelming.

The apparent cause of this change of allegiance by the analysts was their feeling of betrayal that BP had cut its output projections from 5.5% to 3% (a little bit of analysis would have told them that the original target was ambitious, while common observation would have told them that hurricanes in the Gulf of Mexico and earthquakes in Alaska might just impact production).

Meanwhile, Shell's results were better than the analysts expected. The result – their affections were instantly transferred to Shell. Now, in fact, Shell and BP's results were very comparable, but Shell executives are going round with gentle smiles while BP executives have furrowed brows in the face of salary cuts, budget cutbacks and manpower reductions. Can anyone give a rational (or even irrational) explanation of how a small group of analysts have accreted such power? Or why those investing billions take any notice of analysts' mood swings?

Whatever one's views on the merits or demerits of recent political moves *vis-a-vis* Iraq, the idea that major change is now likely is an uncontroversial conclusion. For the international oil and gas industry the opportunity to invest in Iraq is becoming a realistic possibility. UN sanctions applied following the Iraqi invasion of Kuwait and the subsequent Gulf War mean that no company has been able to start work on new projects. However, some Russian, French, Chinese, Spanish, Italian and Australian companies have apparently been negotiating oil project development contracts with the current Iraqi regime.

Only limited information is available and its accuracy and exact status is unclear. The table below is the most comprehensive summary we have been able to find. The Russians have publicly confirmed that they have signed a $20bn contract to develop Iraqi oil fields, the status of the rest is unknown. The Iraqi opposition leader in exile, Ahmed Chalabi, has indicated that all contracts signed by Saddam Hussein will, in the event of regime change, be cancelled or renegotiated. Presumably if UN sanctions are lifted without regime change they will be honoured.

Chris Skrebowski

Oilfield	Company	Reserves (bn b)	Peak prod'n	Value ($)
Majnoon and Bin Umar	TotalFinaElf	26	1mn b/d	$7.4bn
West Qurna PhII	Lukoil	15	600,000 b/d	$3.7bn
Nassiryah	Eni/Repsol	2	300,000 b/d	$1.9mn
Halfaya	BHP	2.5	225,000 b/d	$2bn
Al-Ahdab	CNPC	–	90,000 b/d	$700mn
Amora	PetoVietnam	–	80,000 b/d	$300mn
West Qurna Ph1	Zarubezneft	–	200,000 b/d	$380mn
N Rumaila	Mashinoimport	–	250,000 b/d	$160mn
Mishrif				
Khurmala	Stroyexport	–	100,000 b/d	$190mn
Suba-Luhais	Mashinoimport	–	100,000 b/d	$200mn
Hemrii	Stroyexport	–	60,000 b/d	$120mn
TOTAL			**3.005mn b/d**	**$17.05bn**

Source: www.msnbc.com/news/823985.asp?Ocb=.115114700

Petroleum Review Online

Petroleum Review is now available online as an additional benefit to all Institute of Petroleum (IP) members.

It can be viewed in one of two formats from the *Petroleum Review* Online link on the Home Page at **www.petroleum.co.uk**

- ***Quick-view text version*** – This includes News in Brief, News and all the main feature articles in the magazine, including key tables and graphics. However, please note that Editorial, E-world, Membership material, Publications, Technology News, People page and Events are only available via the PDF version.
- ***PDF*** – The complete printed issue of *Petroleum Review* recreated in PDF format. Please note that we have divided the magazine into five PDF sections in order to speed the downloading process.

We hope that the online version of *Petroleum Review* proves a valuable addition (particularly when travelling) to the hard copy that all IP members will continue to receive.

It is planned that the website and online service will be developed further and the content continuously expanded. One of the plans it to set up a *Petroleum Review* Online database that will allow IP members to search for articles by key word or region of the world.

If you have any comments about how we may improve our online service, please send an e-mail to **petrev@petroleum.co.uk**

IP Newsletter

The Institute of Petroleum is proud to present its online newsletter, created to keep subscribers of *Petroleum Review* and Members of the IP regularly updated about the Institute's work-in-progress, together with the latest news and developments from around the upstream and downstream oil and gas business.

From the IP's ongoing merger talks to up-and-coming events, conferences and training courses, our aim is to provide a comprehensive and informative round-up of the key issues affecting the global industry.

Visit **www.petroleum.co.uk** to find out more.

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

In Brief

UK

BP has made a new gas discovery with *its South West Seymour exploration well located in block 22/5b to the east of the BG-operated Armada field. The find will be developed as a tie-back to Armada, with first gas slated in 2Q2003.*

Talisman Energy (87.43%) has made an *oil discovery in the central North Sea adjacent to the Buchan field. In place reserves are put at 40–70mn barrels.**

The future of BP's Sullom Voe oil and *gas terminal could be in jeopardy following claims that the company plans to halve its costs and decommission some of its processing capacity at the site.**

Eni has rationalised its UK North Sea *portfolio by selling its non-core assets to independent Oranje Nassau for an undisclosed sum. The assets include a 20% stake in the Cook oil field, an 18.2% interest in Janice, a 3.7% stake in the Shell-operated Pierce development, and a 6.3% interest in Amerada Hess' Chestnut discovery.*

Aberdeen-based subsea contractor *Subsea 7 is to sell its geotechnical business to Fugro for $22mn.*

KCA Deutag, a subsidiary of Abbot *Group, claims to have become one of the first offshore drilling contractors in the North Sea to achieve the environment standard ISO 14001.**

Europe

ABB has secured a three-year, $80mn *contract from Norsk Hydro for the design, construction and installation*

Complete news update

The 'In Brief' news items in *Petroleum Review* represent just a fraction of the news we regularly publish on the IP website @ **www.petroleum.co.uk** via the 'News in Brief Service', together with our daily News 'ticker' on the main home page.

Furthermore, those news stories marked with an asterisk (*) in the magazine are covered in more detail on the News in Brief Service.

Why not visit the site to find out more about the latest developments and trends in your industry? Click on

www.petroleum.co.uk

NEWS Upstream

First ever North Sea field brought back to life

The UK Government has given the go-ahead for British companies Tuscan Energy and Acorn to redevelop the first ever UK North Sea oil field – Ardmore, formerly known as Argyll. Activity at the field in block 30/24b came to an end in 1992 when operations became uneconomic and the project was decommissioned; it has been lying fallow ever since.

Tuscan and Acorn plan to utilise the latest well technology to recover 21mn barrels of oil that were previously unreachable. First oil is expected in October 2003. Argyll was opened in 1975 by the then Energy Minister Tony Benn. During the lifespan of the field less than 40% of the oil was retrieved.

Oilfield service provider Expro International is to supply and operate Ardmore's production equipment under a £17mn contract awarded by Tuscan Energy. The equipment will be able to process up to 40,000 b/d of oil and up to 50,000 b/d of produced water.

Middle East upstream developments

Stella Zenkovich reports on recent upstream developments in the Middle East:

- The governments of Japan, Iran and Qatar have reached an in-principle agreement to allow a Japanese consortium to develop gas resources in Iran's South Pars project and Qatar's North field development, claimed to be the largest (13tn cm) and second largest (9.8tn cm) gas reserves in the world, respectively. The consortium – whose key members are Inpex, JNOC and JGC Corporation – plans to produce and export LNG and GTL products to Japan in 2005/2006, raising Japanese gas reliance from 13% to 23%. The total projected development cost from 2003–2005 is Y500bn.
- A consortium led by LG Engineering of South Korea (42%) and including two Iranian contractors, IOEC and OIEC (29% each), has been awarded a $1.6bn contract for the development of phases 9 and 10 of Iran's South Pars gas project that call for the production of 2bn cf/d of gas, 80,000 b/d of condensate and 1mn t/y of LPG.
- Shell is reported to be planning to invest $5bn in the development of gas resources in Qatar, which it is to tap in a joint venture with Qatar Petroleum.

Early production from Recetor in Colombia

Equipo, a Colombian company principally owned by energy services company Wood Group, has signed a five-year contract with BP to design, build, operate and maintain an early production processing facility on the Recetor block in the Casanare region of Colombia. The facility will be capable of handling 30,000 b/d of oil and 80mn cf/d of gas, and will generate its own power.

Oil from Recetor will be supplied to BP's Cupiagua central production facility for which Equipo has a five-year maintenance and operations support contract. Gas will be reinjected into the reservoir, which is an extension of the Cupiagua field in the neighbouring Santiago de las Atalayas licence, to enhance further production.

BP's Cupiagua and Cupiana oil and gas fields provide nearly 50% of Colombia's annual oil production.

Green light for Blake Flank project

The UK Government has given the go-ahead for the £60mn Blake Flank project in the North Sea, development of which will extend the economic life of the producing Blake field by two years.

First oil from two production wells tied into the existing Blake production manifold is slated for 3Q2003. Blake Flank reserves are put at more than 20mn barrels over 10 years. Project partners are BG (44%, operator), Talisman (53.6%) and Paladin (2.4%).

Recent E&P news in Russian and Central Asia

Stella Zenkovich reports on recent upstream developments in Russia and C. Asia:

- The Balaxani-Sabuncu-Ramana deposit – in use for 130 years – remains one of the best onshore Azerbaijan, according to SOCAR. A total 110,354 tonnes of oil were extracted in 1H2002 – some 13,304 tonnes more than planned and 1,025 tonnes more than in the equivalent period of 2001 – generating $6.2mn profit instead of the planned $4.1mn. Remaining reserves are quoted at 43.2mn tonnes, but the application of up to date technology would permit the lifting of an additional 70mn tonnes.
- The Kurmangazy offshore oil and gas field, ownership of which had been disputed for some time by Russia and Kazakhstan, is now being developed jointly by Rosneft and KazMunaiGaz, with drilling expected to start in June 2003. In preparation Rosneft is spending $37mn on repairing and modernising a drillship at two Astrakhan shipyards, Krasniye Barri-kady and Korall.
- Agip KCO, a subsidiary of Italy's Eni, has announced that the international North Caspian Sea Production Sharing Agreement (NCSPSA) consortium it heads has made a second discovery in the Kazakh sector of the Caspian, although it is too early to estimate oil reserves. The first exploration well in the Kalamas offshore structure located 80 km southwest of Kashagan is producing 2,300 b/d.
- The first-stage development cost of the Shakh Deniz gas project has reached $2.2bn, $600,000 more than projected. According to BP it is normal for cost modifications to arise on the basis of detailed engineering and subcontractor proposals. Shakh Deniz costs increased following a re-estimation of work required on offshore platforms to facilitate the installation of upper modules.
- Following the recent agreement between Russian and Kazakhstan delineating the Caspian boundary between the seabed sections of the two countries, Azeri and Russian Presidents Geidar Aliyev and Vladimir Putin, respectively, have inked an agreement regarding delineation between Azerbaijan and Russia.

Renewable energy

The global offshore renewable energy market could be worth £8bn by 2007, with the European market accounting for 90% of this, according to a new report published by the UK Government.

The *World Offshore Renewable Energy Report 2002–2007* also states that:

- The scale and sheer number of offshore wind developments make it the largest sector accounting for over 97% of the forecast expenditure.
- Annual global offshore wind installations will exceed 900 MW by 2007. Although Denmark has the current lead with a forecast of 300 MW over the period 2001–2003, the removal of government subsidies means the UK will become the next major growth market.
- The UK is expected to install 907 MW of wind installations, some 21% of the global new capacity, by 2007.

Globally less than 100 MW of offshore operating capacity has been developed to date.

Deepwater spend

Nearly $58bn is forecast to be spent over the next five years in developing deepwater fields, according to analyst Douglas-Westwood's *World Deepwater Report*. West Africa is expected to lead the field, attracting 38% of the expenditure, followed by the Gulf of Mexico with 32% and Brazil with 23%.

Some 140 deepwater developments are reported to currently be under consideration for development during the period, some of which are small single well tie-backs – many may not actually go ahead. However, taking a conservative view of prospects, the report predicts that at least 32mn boe of deepwater reserves will come onstream compared to the 10bn boe brought onstream over the previous five years.

Some $21bn is expected to be spent on deepwater floating production systems in the five-year period, $18bn on drilling and completing subsea wells, and $11bn on flowlines and control lines. A further $8bn is forecast to be spent on subsea hardware and surface completed wells.

In Brief

*of two modules, weighing 670 tonnes and 300 tonnes respectively, on the Visund oil platform in the North Sea. Work is due to complete in 2005.**

***Marathon Oil is to drill and develop an** additional subsea gas well in the Kinsale Head area of the Celtic Sea offshore Ireland. It is estimated that the base production capacity of the Kinsale area reservoirs will increase from 65mn cf/d to 90mn cf/d when the Greensand well comes onstream.**

***Norway has put out to tender 109** blocks and part-blocks in a bid to realise value in the small and medium-sized fields located in mature parts of the Norwegian Continental Shelf. The deadline for submission of applications is 28 January 2003 with awards expected to be made at the beginning of 2Q2003.*

North America

***Husky Energy has announced that it is** postponing development of its $1.5bn oil sands upgrader project at Lloydminster amidst fears that meeting greenhouse gas emissions regulations resulting from the Kyoto Protocol on Climate Change could force up operating costs.**

***Marathon Oil claims to have secured a** world deepwater production record with the start-up of gas production from the Camden Hills field located in 7,209 ft of water in Mississippi Canyon block 348 in the Gulf of Mexico. The field – the deepest in the recently completed Canyon Express gas gathering system that links the Camden Hills, Aconcagua and Kings Peak fields – is currently producing 50mn cf/d of gas from the first of two wells. It was expected to reach peak production of 100mn cf/d in late November.*

Middle East

***Iranian Oil Minister Bijan Zanganeh is** reported to have stated that Iran is seeking to attract foreign investment into its gas sector as it targets sales to the Asia-Pacific market, in particular India and China. The country currently produces just over 100bn cm/d of gas, with a target of 180bn cm/y by 2005 – much of the increase is to come from the South Pars offshore field.*

***Statoil has taken a share of up to 40%** in, and operatorship of, the offshore*

In Brief

*part of phases six, seven and eight of the South Pars gas project offshore Iran. First production is expected in late 2004.**

***Kuwait Foreign Petroleum Exploration** Company (Kufpec) is reported to have contracted Schlumberger's IndigoPool to market three prospects onshore central Tunisia with estimated total reserves of 98mn barrels of oil. It is also seeking exploration partners for the Seram Non-Bula PSC onshore Seram Island in eastern Indonesia that includes the Oseil oil field with between 114mn and 139mn barrels of oil in place.*

Russia & Central Asia

***BP is understood to be selling a 2.5%** stake in the Baku–Ceyhan oil pipeline to ConocoPhillips for an undisclosed sum. BP will retain a 30.1% interest in the project that carries Azeri gas to Turkey's Mediterranean coast.*

Asia-Pacific

***Inpex Corporation is reported to have** made a huge gas discovery in the Masela block offshore Indonesia with reserves thought to exceed 4tn cf – large enough to make an LNG project viable. The company is planning to produce LNG on a commercial basis as early as 2010.*

***BHP Billiton is reported to be planning** to increase its oil production by 38% to 180mn boe over the next five years as it brings onstream new projects including the Gulf of Mexico Mad Dog field in 2004 and Atlantis in 2005, Zamzama in Pakistan in 2003, Minerva in eastern Australia in 2004, and Ohanet and Rod in Algeria in 2004.*

***Santos reports that Mutineer reserves** offshore Australia are between 50mn and 130mn barrels.**

***Cairn Energy (50%) has reported that** the Lakshmi gas field in block CB/OS-2 in western India has come onstream. The project is contracted to supply 120mn cf/d to Gujarat Gas Company and Gujarat Powergen Energy once production reaches plateau.*

***ConocoPhillips has announced that the** Rang Dong field in Vietnam block 15-2 has achieved first oil from two new wellhead platforms, boosting total field production by 40% to 65,000 b/d.**

NEWS Upstream

UK oil output continues to fall

According to the Royal Bank of Scotland's October *Oil and Gas Index*, August oil production fell by 5.5% on the month and 9.3% on the year to 1,831,386 b/d – its lowest level since March 1992. Gas production in August 2002, however, was up 10.5% on a month earlier, at 8,703mn cf/d – although still down on the year by 5.8%.

Senior Economist Tony Wood commented: 'Oil production was at its lowest level for a decade in August. However, much of the decline is attributable to a power failure on a single field. Overall market sentiment remains dominated by the prospect for conflict in Iraq. This appears to be impacting on investment globally and the situation of high oil prices and constrained investment looks set to continue over coming months.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Aug 2001	2,018,982	8,814	25.60
Sep	1,984,388	9,091	25.90
Oct	2,169,226	8,909	20.60
Nov	2,161,755	11,949	18.80
Dec	2,425,159	12,621	18.60
Jan 2002	2,270,322	12,303	19.30
Feb	2,247,395	11,732	20.20
Mar	2,153,321	11,640	23.80
Apr	2,230,781	11,182	25.70
May	2,106,088	9,962	25.50
Jun	2,143,228	9,118	24.10
Jul	1,939,209	7,882	25.70
Aug	1,831,386	8,703	28.40

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

UK fabrication promo

A new £210,000 Offshore Energy Centre has opened at the Amec yard in Wallsend on Tyneside in the UK, showcasing British fabrication expertise.

The centre aims to bring more multi-million contracts and jobs throughout the UK, building on recent success stories for northeast fabrication yards such as the securing of contracts related to Shell Nigeria's Bonga and BP's Clair projects that have created more than 2,000 jobs.

The joint government-industry sponsored 'shop-window' for the oil and gas sector is planned to serve a dual purpose:

- Acting as a permanent trade mission to sell UK offshore expertise to UK and international clients.
- Linking up with schools and colleges to attract young recruits to the energy sector.

Lukoil expansion

According to Lukoil Vice President Leonid Fedun the company is targeting production of 1.8–1.9mn b/d of oil in 2007 and 2mn b/d in 2010, reports UFG.

Lukoil is planning to compensate for stagnant production at its traditional Volga-Urals and Western Siberian oil fields with accelerating production in new areas such as Timan-Pechora and the Caspian.

The company is also targeting faster development of its gas sector during 2005–2006 as the liberalised industry gains momentum and independent gas producers have clear access to Gazprom's pipelines.

It has set a production target of 25–30bn cm of gas in 2007–2008, placing it second after Gazprom in terms of total gas output.

NEWS Upstream

Tullow expands North Sea portfolio

Tullow Oil is to expand its acreage portfolio in the southern North Sea by acquiring GDF Britain's 20% equity interest in block 44/17b where it is planned to drill a well on the Monroe Carboniferous prospect in 1H2003. The company considers Monroe to have similar potential to Hawksley, one of the five Caister-Murdoch System (CMS) III satellite fields that are in close proximity to the prospect. Tullow will have a pre-unitised equity interest of 15% in the Monroe prospect that straddles an adjacent block held by the CMS III partners. In the event of a commercial discovery, the development could be tied back to the CMS infrastructure for early production.

Tullow is also to acquire from Conoco a 20% equity interest in five blocks or part blocks offshore Lincolnshire – blocks 47/19, 47/20, 47/24a, 47/25 and 48/16b. A well is scheduled for drilling on block 48/16b in late 2002 to test the Islay prospect.

Upstream developments in Africa

Stella Zenkovich reports on recent developments upstream Africa:

- Some 66 of Nigeria's 70 indigenious oil companies have prequalified for the second phase of the bidding round for 24 marginal field blocks put out to tender by the federal government.
- Long-awaited drilling for oil has finally started in the rift valley of western Uganda by Eagle Drill on behalf of exploration licensee Heritage Oil & Gas of Canada.
- Sao Tome and Principe is seeking to invalidate the treaty for a joint development zone with Nigeria for oil prospecting and exploitation in the oil-rich Gulf of Guinea that is estimated to hold 4bn barrels of reserves. It is reportedly disillusioned by the lack of willingness for co-operation on the part of the Nigerians.
- Nigeria is planning to increase production to 3mn b/d and boost its crude reserve base to 30mn b/d in 2004, and then to 4mn and 40mn respectively by 2010.
- In a prolongued border dispute between the Cameroon and Nigeria, the World Court in The Hague has ruled in favour of the Cameroon, stating that it was the rightful owner of the oil-rich Bakassi peninsula. Nigeria has accepted the decision.
- The Polish Government of ex-communist PM Leszek Miller expects to secure exploration rights for Polish companies in each country in return for scrapping communist-era state debts of the Sudan, Libya and Angola.

Hydro to become a 500,000 barrel company

Norsk Hydro reports that it is 'on the way to becoming a 500,000 barrel oil company'. At the end of October the company produced 533,000 boe/d, some 60,000 barrels of which were produced from fields outside of the Norwegian Continental Shelf. The company also reports that increasing oil production in 2H2002 has led to an upward adjustment of forecast annual production by 15,000 b/d to 470,000 b/d. It expects to maintain a production level of around 500,000 boe/d in 4Q2002 – some 40,000 barrels more per day than the average production level in the first three quarters of the year.

According to Kjetil Solbraekke, Vice President Finance in Oil and Energy: 'The high production is a result of very great demand for gas from customers on the continent. In addition, the fields that were closed down for maintenance earlier this autumn are now in production again. We have also noticed a gain from the SDFI units we purchased in May, which increased our ownership in the Oseberg fields.'

Norsk Hydro's present production record was set in mid-July, when daily output reached 541,000 barrels. Solbraekke does not rule out the possibility that the record may be broken later this year. Important factors would include the demand for gas staying at the forecast level – around 140 boe – and the North Sea Tune field coming onstream as planned.

In Brief

***Reliance Industries is reported to have** made a large gas discovery offshore India in exploration block KGB-6 in the Andhra Pradesh Godavari Basin. It is estimated that the new find could produce 40–50mn cm/d of gas, almost doubling the country's potential gas production.*

Latin America

***The Brazilian authorities are understood to be planning to offer blocks** in nine basins – Barreirinhas, Campos, Espirito Santo, Foz do Amazonas, Jequitinhonha, Pelotas, Potiguar, Reconcavo and Santos – in a fifth licensing round scheduled to take place in June 2003. The blocks are to be offered under a new, flexible bidding programme, whereby bidders will be able to define the size of the blocks by building them from smaller 'cells'. Licenses for 824 cells offshore and 298 onshore units in 21 sectors are to be put out to tender.*

***Petrobras has brought onstream the** Jubarte field in the deep waters of Brazil's Campos Basin. The field is currently producing 16,500 b/d of oil and 100,000mn cm/d of gas from one well. A total of five wells are planned. Field reserves are put at 600mn barrels of heavy oil.*

Africa

***Media reports say Nigeria, Sao Tome** and Principe have abandoned plans to open bids for licenses for 10 blocks in the Gulf of Guinea. It is understood the West Africa countries' commission must first resolve 'contentious issues' on their joint development zone.*

***Talisman Energy is to sell its indirectly** held 25% interest in the Greater Nile oil project in Sudan to ONGC Videsh, a subsidiary of India's Oil and Natural Gas Corporation, for $758mn.*

***Fortesa International of the UK is** reported to have brought onstream the Gadiaga gas field in Senegal. The field is producing 2mn cf/d of gas for power plants near Dakar.*

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In Brief

UK

***Coflexip Stena Offshore, the UK arm** of Technip-Coflexip, has changed its name to Technip Offshore UK.*

***Offshore renewable energy is** expected to grow and become a $1bn market by 2007, according to analyst Douglas-Westwood. During the period 2002–2007 over $4.5bn in capital expenditure is forecast, with offshore wind accounting for nearly 97%, wave 3% and tidal/current stream <1%. Europe is expected to maintain its current dominant position with over 90% of global expenditure.*

Europe

***Statoil has posted a 3Q2002 net profit** of NKr3.3bn compared to NKr4.08bn in the same period a year earlier.*

***Dutch gas distributor Gasunie is** reported to be reviewing the possibility of joining the Gazprom-led consortium that is building a $3bn gas pipeline under the Baltic Sea to link Finland and Europe. Once completed in 2010 the 30bn cm/y pipeline will handle some 25% of Russian gas exports to Europe.*

***Wintershall Nederland has completed** the takeover of Clyde Netherlands after receiving unconditional approval from the German and Dutch competition authorities.*

***Norsk Hydro has reported a 3Q2002** net income of NKr513mn compared to NKr1,333mn a year earlier.*

***Engineering company ABB is reported** to have put its oil, gas and petrochemical division up for auction in order to save the group from bankruptcy. The company, which posted a $4.1bn debt at the beginning of 2002, plans to reorganise and focus on power and automation technologies.*

North America

***Retailers Market Xchange (RMX), an** independent spin-off of Chevron that served multi-branded fuel distributors and retail suppliers, has ceased to trade after nearly two years in business. RMX was an outgrowth of Chevron's Retailers Alliance (CRA), which continues to operate and serve branded retail sites.**

NEWS Industry

Securing European gas supplies

For an enlarged European Union to have secure supplies of gas, capital investments of up to 500bn could be required between now and 2020, according to a report delivered by the International Association of Oil & Gas Producers (OGP) to the Madrid VI Regulatory Forum in Madrid at end-October. The twice-yearly forum brings together the EU Commission, Member State gas regulators and major operators in the gas industry. While the enlarged EU could have all the gas it needs for the balance of this century, the OGP reminded the Forum that political, legal and economic stability will be key determinants in meeting the risk criteria of investors.

The report highlights a number of key findings and recommendations, including:

- Within the EU, future indigenous gas potential is about 13,000bn cm. At current consumption levels this would be equivalent to supplying the EU area with gas for the next 30 to 40 years.
- Additionally, gas resources that under the right conditions could be available for export to Europe from such areas as North Africa, Central Asia, West Africa and the Carribbean total about 180,000bn cm.
- Of this figure for export to Europe, some 60,000bn cm consist of undiscovered potential that would rely on a supportive and enabling framework policy for the necessary exploration, production and infrastructure investment to bring these volumes to market.

Much of the gas from outside the EU area would have to travel considerable distances – either through pipelines or as LNG – to reach the European market. Reliable infrastructure needs to exist, including the legal framework to facilitate construction of such networks, states the OGP report. If confidence in the ability to operate a project profitably over a long period is not given, foreign investors and exporting countries alike could be hesitant to enter into such projects, the report emphasises.

Meanwhile, the EU's own production will continue to play an important role in the overall supply portfolio. Therefore, OGP stresses that it is essential that all measures be in place to encourage optimal development of domestic resources.

Copies of the OGP report can be found at www.ogp.org.uk

Industry developments in the Middle East

Stella Zenkovich reports on recent industry developments in the Middle East:

- Saudi Arabia is optimistic that Western oil majors will accept its last-ditch offer of improved terms to invest up to $25bn in its gas sector that is being opened to foreigners for the first time. The 'final offer' has been made clear in a letter from Foreign Minister Prince Saud al-Faisal to ExxonMobil and Shell. By committing the country to provide stated gas volumes without mentioning specific acreage, and thus where the gas will come from, Riyadh is aiming to preserve Saudi Aramco's monopoly.
- National Iranian Oil Company (NIOC) has informed Indian Oil Company (IOC) that it wants to exit Chennai Petroleum (CPCL), an IOC subsidiary in which NIOC holds a 15% stake. The move would clear the decks for a merger in the longer term between IOC and CPCL.
- Russian Economic Development and Trade Minister German Gref has told ORT TV in Vienna that Russia can easily compete with Arab countries to supply oil to the US market, and that deliveries from its proposed Murmansk deepsea oil port will be much cheaper than Arab oil due to lower transportation costs.
- In Israel, Eliat-Ashkelon Pipeline Company is planning to reverse the flow of the 254-km pipeline built during the Shah's rule for carrying Iranian crude from the Red Sea to the Mediterranean so that it can now carry Central Asian, Kazakh Tengiz and Russian Urals crude.
- The Paz-Africa-Israel consortium has filed a lawsuit with Tel Aviv District Court against the government for allegedly arbitrarily allocating the $400mn gas grid contract to Israel Electric Corporation.
- Iraq's rebuilding of its oil industry in the wake of a US attack would take 18 months and the price of oil would drop to $12/b as a result, according to Mikhail Kodorov-sky, CEO of Russian oil major Yukos.

NEWS Industry

Industry developments in Russia & C. Asia

Stella Zenkovich reports on industry developments in Russia and Central Asia:

- Originally planning to sell a 5.27% stake less one vote, plus a 19.68% package separately in Russo-Belarus oil company Slavneft despite objections from the Belarus Government, Moscow has switched to offering a 74.96% complement for $2bn. Lukoil, Yukos, Surgutneftegaz, Sibneft and TNK are reportedly interested.
- Pakistan claims to have no objection to the laying of the Trans-Afghan pipeline for carrying Turkmen gas over Afghan territory into Pakistan and perhaps on to India. However, with 750bn cm of proven gas reserves set and a forecast 50% increase in domestic gas production to 3.7bn cf/d by end-2003, Pakistan cannot really be regarded as a prospective buyer. Furthermore, its present relations with India are unpromising.
- Lebapnebitgazgurlusyk, the oil and gas contractor's directorate 4, was on schedule to complete the 80-km Hojahayran-Kelif gas pipeline in eastern Turkmenistan, close to the Afghan border, by late November 2002. The new gas artery is to improve supply to the populated areas and industrial enterprises of Magdanly city and Koytendag district.
- RWE Gas, the German owner of much of the Czech gas industry, is selling its 21.47% holding in oil and gas company Moravske Naftove Doly (MND) to majority holder Eurogas for an undisclosed sum.
- Kazakh-Greek negotiations are underway regarding the shipping of Kazakh crude from Novorossiysk – piped there by CPC's Tengiz-Novorossiysk pipeline – via a joint Kazakh-Greek tanker fleet sailing under the Kazakh flag to Alexandroupolis according to the Russian Itar-Tass news agency. Furthermore, Greece is reported to have offered to invest $500mn in oil projects in the Kazakh sector of the Caspian.

BP reviews output growth targets

At the end of October, BP posted a 3Q2002 pro forma result, adjusted for special items, of $2,294mn compared with $2,645mn a year ago, a reduction of 13%. Group Chief Executive Lord Browne reported that: 'The trading environment has shown little improvement overall and, for the nine months, is well down on a year ago. Performance improvements have been impacted by weaker than expected production.' He stated that the company is to review its future output growth targets as the expected output increase for the year now stands at 3% versus the 5.5% forecast in August.

Lord Brown also commented that the 5.5% target for the years to 2005 would cost an extra $1bn/y to achieve. Return on average capital employed for the nine months was 13% compared with 22% in 2001.

Investors reacted rapidly at the news and BP's shares fell 7.2% on the day.

In contrast, Shell reported more positive results, posting a net income of $2.6bn for 3Q2002, 7% higher than a year ago. Adjusted current cost of supplies (CCS) earning for the quarter were 17% lower at $2.2bn, bringing the year to date total to $6.4bn. The return on average capital employed on a CCS earnings basis for the first nine months of 2002 was 11.9%.

The company aims to increase production by 3% per year on average between 2003 and 2005.

Consultant register launched by InstE

A new project has been initiated with the Institute of Energy to develop Consultant Registration for the mutual benefit of energy consultants and customers of the Action Energy programme. Action Energy is a UK Government backed initiative run by the Carbon Trust that works with organisations large and small to reduce costs and improve environmental performance. Since its launch in 1989 the programme has helped the UK economy save up to £800mn/y – equivalent to over 3mn t/y of carbon.

To operate a number of its services Action Energy requires access to a qualified body of skilled energy consultants. Over the coming months the Institute of Energy – a Royal Charter professional body currently in merger talks with the Institute of Petroleum – will work with Action Energy to transfer currently registered consultants to the new registration system that is hoped will become a 'kite mark' of the energy consultancy profession.

In Brief

***ExxonMobil has reported a $380mn** fall in its 3Q2002 earnings to $2,940mn compared with $3,320mn in the same period a year earlier. ChevronTexaco posted a net loss of $904mn for the third quarter while ConocoPhillips posted a 3Q2002 net operating income of $456mn compared to $373mn a year ago. Marathon Oil reported a net income of $149mn for the period and Amerada Hess operating earnings, excluding special items, of $121mn. Kerr-McGee reported a $86.8mn loss for 3Q2002 after incurring $146.4mn costs from higher income taxes in the UK. Halliburton posted a 47% fall in quarterly earnings to $94mn from $179mn a year earlier.**

Russia & Central Asia

***Prime Minister Mikhail Kasyanov has** stated that a privatisation auction for the state's 74.96% stake in Slavneft will be held no later than 20 December 2002, reports UFG.*

***Gazprom has reported that its exports** to Europe rose by 3.2% in the first nine months of 2002 compared with the same period last year. Exports to Western Europe rose by 2.7% with Turkey showing an increase as well as the Netherlands, where deliveries started under a new contract, reports UGF. Central European gas sales rose by 4.5% over the same period.*

***Sibneft has reported a 19% increase in** revenues for 1H2002 to $1.984bn from $1.663bn in 1H2001.*

Asia-Pacific

***Pertamina of Indonesia is reported to** have signed cooperation agreements with Petronas of Malaysia and Brunei under which they will jointly transport and market up to 2.36tn cfly of LNG. It is hoped the agreements will stabilise LNG prices and security of supply.*

***Shell Philippines is reported to be considering** an initial public offering by 1Q2004, depending on the prevailing market conditions at that time. Under the Philippine's oil deregulation law, oil companies must conduct a public offering of 10% of their shares.*

MANY OF THE MONTH'S INDUSTRY NEWS STORIES NOT INCLUDED ABOVE CAN BE FOUND ON THE NEWS IN BRIEF SERVICE @ www.petroleum.co.uk

In Brief

UK

The UK's new Electricity Safety, *Quality and Continuity Regulations 2002 are due to enter into force on 31 January 2003. To view the regulations, visit* **www.legislation.hmso.gov.uk/si/si2002/20022665.htm**

Vopak is to sell its 50% stake in the *shipping agency Clarkson Brothers of Middlesbrough in the UK.*

The UK Government has launched a *probe into the performance of UK energy suppliers after hundreds of thousands of consumers were left without power for days following the violent storms that struck the UK over the 26 and 27 October. Earlier this year the government commissioned a study into the resilience of the UK electricity infrastructure and its ability to cope in extreme conditions – the main report can be viewed at* **www.dti.gov.uk/energy/bpfinalreportelec.pdf**

Europe

BP is to sell, subject to the necessary *regulatory approvals, its 70-strong service station network and other inland fuel businesses in Cyprus to Hellenic Petroleum for an undisclosed sum. BP Cyprus sells some 500mn l/y of fuel and is the leading fuel retailer in the country, holding a 35% market share.**

Lukoil is reported to have formed a *German subsidiary – Lukoil Hamburg – that hopes to acquire 460 Aral-branded service stations in the north of the country from BP. Tatneft and OMV are reported to both be interested in buying a further 340 outlets in southern Germany.*

Lukoil is reported to be considering *the withdrawal of its bid for a 23% stake in Greek oil refiner Hellenic Petroleum.**

North America

CMS Energy of Michigan, US, is understood *to be considering an exit from the gas and power trading sector. It would join a number of companies that have already withdrawn from the US trading arena, including Dynegy and Allegheny, as the market struggles to cope with increasingly stringent credit requirements following the collapse of energy trader Enron.*

Iran may join Energy Charter

Iran is exploring the possibility of involvement in the work of the Energy Charter, an inter-governmental organisation promoting energy cooperation in which 51 European and Asian states participate (see *Petroleum Review*, November 2002). Dr Ria Kemper, Secretary General of the Energy Charter Secretariat, recently met with key Iranian Government officials to discuss strengthening international cooperation with regard to energy trade, transit, investments and energy efficiency.

At present Iran is the only littoral state of the Caspian Sea that is not a member of the Energy Charter process. In Dr Kemper's view this is one reason why Iran's participation would be a welcome development. 'The Energy Charter offers its member governments a forum for discussions of energy policy matters, in particular with regard to the security of oil and gas exports from emerging production areas in the Caspian Basin and Central Asia,' she noted. 'As an important producer-state, but also as a potential transit route to world markets for Central Asian energy resources, Iran in my view has a clear interest in participating in these discussions within the Charter's framework.'

As a next step in developing its relations with the Charter, Dr Kemper invited the Iranian Government to apply for observer status at the Energy Charter Conference, the organisation's governing body. Should such an application be accepted, Iran would become the seventh Opec member country to be granted observership at the Energy Charter, the others being Algeria, Kuwait, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela.

Cutting home greenhouse gas emissions

Reducing greenhouse emissions from home water heating could be achieved at about one-third the cost of current Federal, State and Territory government solar water heater incentive schemes, by encouraging the uptake of five-star (high efficiency) natural gas water heaters, according to new research by the Australian Gas Association (AGA). It is claimed that this would cost $2.7mn/y, a potential saving for taxpayers of $5mn/y on the current solar schemes.

Most State and Territory governments have introduced subsidies to encourage householders to purchase solar water heaters. These taxpayer-funded subsidies have been estimated to cost $7.7mn in the past year. The Commonwealth's Renewable Energy Certificates (RECs) scheme, while not taxpayer funded, also provides a financial incentive to encourage a switch to renewable energy. The solar water heater component of this scheme has been estimated to cost $10.1mn in the past year.

The AGA research paper also states that subsidies for 'greenhouse friendly' water heating should be 'technology neutral' and targeted according to the emissions performance of water heating systems rather than particular energy types. However, the preferred long-term sustainable solution is to develop an energy market that reflects the full cost of greenhouse emissions in energy prices. This would greatly benefit both solar and natural gas, comments AGA.

According to the report, based on daily water use of 200 litres:

- water heaters produce 4.8 t/y of greenhouse gases;
- electric-boosted solar water heaters (warm climate) – 1.2 t/y;
- electric-boosted solar water heaters (cool climate) – 1.9 t/y;
- two-star natural gas water heaters – 1.6 t/y; and
- five-star natural gas water heaters – 1.3 t/y.

The research also emphasises that a simple fossil fuel versus renewables approach to energy policy is now outdated. 'Under a more sophisticated low emission energy versus high emission energy approach, technologies such as natural gas and solar have a key role to play, and there are clearly grounds for a productive alliance between the two.'

Algerian gas to be marketed in Europe

TotalFinaElf and state-owned Sonatrach have signed a Letter of Intent governing the purchase of 1bn cm/y of Algerian gas. The gas will be delivered to TotalFinaElf in Europe via the future pipeline connecting Algeria directly to Spain, currently under study by the company Medgaz. Sonatrach and TotalFinaElf have respective 20% and 12% stakes in the Medgaz project, partnered by Cepsa (20%) and BP, Gaz de France, Endesa and Eni (12% each). The pipeline has a planned capacity of 8bn cm/y of gas, with the possibility of increasing to 16bn cm/y.

Downstream Russia & Central Asia

Stella Zenkovich reports on recent Russian and Central Asian downstream news:

- Following a year-long investigation, UOHS, the Brno-based Czech office for the protection of economic competition, intends to fine heavily key players in the Czech fuel retail market for having operated a price-fixing cartel for years and depriving motorists of the benefit of a competitive market. Fines totalling Ck300m ($9.7mn) are anticipated for Benzina, OMV-CR, Shell, Agip and ConocoPhillips. Shell, already fined Ck65m, is appealing while ConocoPhillips denies the charge. The Czech anti-monopoly office is following in the footsteps of its Italian and Swedish counterparts who have taken action against fuel retailers in recent years.
- The Council of Ministers of the Muslim-Croat Federation of Bosnia-Herzegovina has issued a decree under which it will only allow the entry of liquid fuels conforming to EU standards.
- Serbian gas consumers will either punctually pay their bills or face the halting of their gas supplies, DG Dimitrije Vukcevic of state oil and gas monopoly NIS has declared, adding that otherwise the company will be unable to pay its Russian partner. Gazprom has been supplying 2bn cm/y of gas to Serbia under a government-level agreement concluded with the Milosevic regime. It delivered 165mn cm in October and 236mn cm in November at an increased tariff, and issued a stern warning that supply will stop on 1 December unless a satisfactory proposal is received regarding the $255mn of debt that has piled up from 1994–2000. Having paid only for 60% of gas supplied, NIS has managed to keep up payments in 2001/2002 – but it may be getting tough with consumers too late.
- Petrol and an Israbenz-led consortium are bidding from Slovenia for a 54% majority stake in fuel distributor Jugopetrol-Motenegro.
- Lukoil is planning to add 16 filling stations by the end of the year to its existing network of 134 in the Ukraine, 70 of which are located in Kiev and Odessa and 20 in the Crimea.

IPE trading records

The International Petroleum Exchange (IPE) has reported that October 2002 marked the best month on record for total market volume and a record month for its Gas Oil futures contract.

Total market volume for the month was 2,894,945 lots compared to the previous record of 2,780,644 lots set in September 2001, an increase of 4%. The underlying value of these trades equated to $73.2bn.

IPE Gas Oil futures traded 865,411 lots in October 2002 – an increase of 17% over July 2002 when a record 739,590 lots were traded.

Statoil targets US

Statoil and El Paso Corporation have signed an agreement under which Statoil will secure direct access to the US gas market through the Cove Point LNG terminal in Maryland. El Paso is to release the capacity rights for 20 years, which amounts to one-third of the capacity at the LNG terminal.

The companies have also agreed that Statoil will take over the purchase contract for 2.4bn cm/y of LNG from the Snøhvit field between 2006–2023 and supply power utilities and local distribution companies in the US. The cash payment to El Paso is $210mn.

Fuel cell first

Helion, a subsidiary of French company Technicatome, is reported to have developed what is claimed to be the first proton exchange membrane (PEM) fuel cell.

The company's objective is to design and build a power source based on PEM-type fuel cells with a power of about 300 kW, capable of satisfying the requirements of both the transport and shipbuilding sectors.

Contract renegotiation

ChevronTexaco is in discussions with Dynegy to negotiate an early termination of the contracts under which Dynegy Marketing and Trade purchases substantially all of ChevronTexaco's lower-48 US gas and supplies the gas requirements of ChevronTexaco refineries and other corporate facilities. The discussions were initiated following Dynegy's decision to withdraw from the gas marketing and trading business.

In Brief

Stella Zenkovich ***reports that Israel's*** *Marlaz, Polar Investments and DIG Electrical & Lighting Products have concluded a deal to buy for $39mn 169 filling stations and convenience stores in the US from Fas Mart. Marlaz put down a deposit of $2mn and has announced that a US company may join as a partner.*

Fortum has brought onstream what it *claims is the world's first isooctane plant in Edmonton, Canada. Isooctane is a high-octane, hydrocarbon-based component of gasoline used in cleaner motor fuels such as low sulfur fuels. Total plant production is to be sold to the Californian market.*

InterContinentalExchange (ICE) has *announced the formation of The 10x Group, a market data services company with offices in Houston and London. For more information, visit* **www.10xGroup.com**

Russia & Central Asia

Lukoil is reported to have submitted a *separate application to bid $274mn for a 75% stake in Poland's 90,000 b/d Gdansk refinery and invest at least $330mn in the facility over the next five years. 'In September, Lukoil's partner in a joint bid, Rotch Energy, switched sides and approached PKN Orlen, Poland's largest refiner and seemingly the preferred bidder for the plant,' comments UFG.*

Russia is planning to increase its 2003 *gas tariff by more than the 20% the government originally stated would be the maximum increase. It is now proposing increases of 30–35%.*

Asia-Pacific

CNOOC is understood to be planning *to build a 12mn t/y refinery in Huizhou City in southern China's Guangdong Province. The facility will provide raw materials for the CNOOC/Shell Nanhai ethylene project, also based in Huizhou and due onstream in late 2005.*

Shell has introduced low sulfur diesel *at 60 service stations in the Australian state of Victoria, beating the deadline for the introduction of government legislation limiting the sulfur content to 500 ppm by three months. The new fuel contains less than half the sulfur content of diesel currently sold in Victoria.*

In Brief

***BP subsidiary BP Petco is understood to** have opened its first LPG bottling facility in Vietnam's southern Nha Be district at an initial cost of $2mn. The plant currently has a 15,000 t/y capacity, which will rise to 50,000 t/y by the end of 2005 following an additional $7mn investment.*

Latin America

***Repsol YPF and Syntroleum are understood** to have signed a Memorandum of Understanding to jointly undertake pre-engineering assessment studies on developing two gas-to-liquids (GTL) projects in Bolivia.*

***ChevronTexaco company Fuel and** Marine Marketing (FAMM) has signed a Memorandum of Understanding with PetroJam to market and supply bunker fuels throughout the ports of Jamaica from January 2003. The companies will initially focus on marketing their products out of the port of Kingston.*

Africa

***Ghana's Tema oil refinery will soon** start exporting fuel and LNG following the completion of its residual fuel catalytic cracker (RFCC), according to* Stella Zenkovich. *The refinery produces 240 t/d of LNG and has a 4,000 tonne storage capacity.*

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NEWS Downstream

World-first for biofuel feedstock

Left to right: United Oilseeds MD Martin Farrow, Huntingdon-based farmer Barwell Field, Greenergy MD Andrew Owens and REFA MD Robin Twizzel

A field in Huntingdon, Cambridgeshire, has become home to what is claimed to be the world's first carbon-certified crop of rapeseed to be used for powering vehicles. Fuel manufacturer Greenergy is investing in the crop with United Oilseeds (who provided the seed stock), Renewable Energy from Agriculture (REFA) and farmer Barwell Field – it is understood to be the first such collaboration between the green fuels sector and the farming community.

The crop will be used in the production of Greenergy GlobalDiesel (see *Petroleum Review*, November 2002), a mix of processed rapeseed oil (5%) and ultra low sulfur diesel (ULSD, 95%). The fuel is reported to deliver a guaranteed whole-of-life carbon dioxide emissions reduction of 5% as well as improved fuel consumption and up to 28% less particulate emissions than ULSD – all without requiring any engine modification.

The 35-acre site at Nook Farm is expected to yield some 55 t/y of rapeseed. This is equivalent to almost 30,000 litres of rapeseed oil which, when converted into pure biodiesel and blended with ULSD, can supply some 560,000 litres of GlobalDiesel.

UK Deliveries into Consumption (tonnes)

Products	†Sept 2001	†Sept 2002	†Jan–Sept 2001	†Jan–Sept 2002	% Change
Naphtha/LDF	59,983	186,236	1,222,162	988,326	–19
ATF – Kerosene	1,013,956	1,014,736	7,945,898	7,701,994	–3
Petrol	–	–	–	–	–
of which unleaded	1,770,957	1,554,828	14,994,121	14,627,702	–2
of which Super unleaded	36,942	53,452	300,269	425,545	42
of which Premium unleaded	–	–	5,465,882	–	–100
ULSP (ultra low sulfur petrol)	1,712,080	1,501,376	9,227,970	14,202,157	54
Lead Replacement Petrol (LRP)	67,246	31,584	692,631	424,045	–39
Burning Oil	349,014	302,927	3,305,130	2,714,197	–18
Automotive Diesel	1,315,208	1,424,029	11,878,258	12,591,872	6
Gas/Diesel Oil	500,892	512,975	4,285,684	4,513,958	5
Fuel Oil	114,048	139,368	1,559,419	1,393,588	–11
Lubricating Oil	69,830	62,796	684,822	616,344	–10
Other Products	574,955	644,023	5,763,157	6,095,482	6
Total above	5,836,089	5,873,502	52,708,248	51,667,508	–2
Refinery Consumption	391,117	407,421	3,703,657	3,731,228	1
Total all products	6,227,206	6,280,923	56,411,905	55,398,736	–2

† Revised with adjustments

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

Mixed fortunes

Photo: Origin Energy

While there have been some positive outcomes for Australia's downstream gas industry in 2002, there are also some ongoing challenges, writes *Bill Nagle*, Chief Executive of the Australian Gas Association (AGA)*.

It has been a big year for the Australian gas industry, on a wide variety of fronts. Not only have critical government policy and regulatory issues dominated the industry's attention, but there were also some key infrastructure and gas market developments around the country.

These developments included:

- The construction of Duke Energy International's major underground and subsea gas pipeline from mainland Australia, across Bass Strait, to Tasmania.
- An announcement by TXU, Origin Energy and International Power that they will construct a major gas pipeline between Victoria and South Australia, scheduled to be in commercial operation by January 2004. (See map outlining SEA Gas pipeline route.)
- A crop of new gas-fired power stations or generating units coming online, including in Victoria, South Australia and Queensland.

Origin Energy's Quarantine power station in South Australia – one of the new gas-fired power stations operting in Australia in 2002

- New South Wales, Victoria and the ACT becoming the first jurisdictions in Australia to introduce full gas retail contestability.

Proposals are still being considered for two pipelines to bring gas onshore to Australia – one extending from the Sunrise gas field in the Timor Sea to Darwin, and the other from Papua New Guinea to Queensland (which would then also take gas into the south-eastern Australian markets, largely through the existing pipeline network).

An alternative proposal for Sunrise gas has been mooted, however, which would see the gas processed on a floating offshore facility and transported directly to key overseas markets. The Australian Gas Association (AGA) together with the Northern Territory Government have argued that the onshore option, if chosen, would have much greater benefits for the domestic gas market. (A decision regarding the future development of Sunrise was due to be announced as *Petroleum Review* went to press.)

Diagram: Origin Energy

Figure 1: Proposed route for the SEA Gas pipeline. Note: The smaller lines leading off the main route are proposed laterals to regional towns/areas.

National Energy Policy

A key development during the year was progress made by Australia's Federal, State and Territory governments on the formation of a National Energy Policy. In a communiqué issued last year by the Ministerial Council on Energy (the body comprising Energy Ministers from the Federal, State and Territory governments), explicit recognition was given to the important role that natural gas will play in the Policy, given its domestic abundance, flexibility and environmental benefits.

The first major component of the National Energy Policy development process – the Energy Market Review – has been underway for much of this year. In addition to considering issues relating to the wider energy market, the Review has been identifying ways to encourage the wider penetration of natural gas in Australia. It has also been examining regulatory impediments to the increased interconnection of gas infrastructure in Australia.

The Energy Market Review is set to provide a final report to Australia's governments by the end of 2002. It is then anticipated that work on developing the wider National Energy Policy will be progressed during 2003.

Effective life caps

Another significant policy development for the downstream gas industry during the year was the Federal Government's announcement in May that it would cap the effective life depreciation schedule for long-lived gas distribution and transmission infrastructure at 20 years, rather than extending it out to the 50 years mooted by the Australian Taxation Office.

The AGA welcomed the outcome, given that a 50-year cap would have meant a much lower rate of depreciation on gas pipelines and distribution networks, and consequently would have severely threatened the development of billions of dollars worth of gas infrastructure. However, the AGA has recently been warning both the Federal Government and the Australian Competition and Consumer Commission (ACCC) that the current regulatory price-setting process for gas pipelines and distribution networks may undermine the intended purpose of the 20-year cap.

Two regulatory decisions released this year by the ACCC and Victoria's Essential Services Commission (ESC) have been based on post-tax revenue models. Under these models, companies investing in regulated energy infrastructure projects could be denied the positive taxation and cashflow implications that the effective life cap was designed to provide.

At the time of going to press, the AGA was continuing discussions with the Federal Government and ACCC on this issue.

Regulatory developments

While recent government support for natural gas has been encouraging, the regulatory regime under which the Australian downstream gas industry operates has not been as conducive to the expansion of the gas network. This was again highlighted in 2002.

Since its introduction in 1997, the National Gas Code – the key mechanism for downstream gas industry regulation in Australia – has tended to produce inflexible, low 'rate of return' rulings rather than the genuine, incentive-based regulation originally promised by governments. This is discouraging further investment in both greenfields and existing downstream gas infrastructure.

In essence, the regulatory arrangements need to be modified, to make them flexible enough to ensure gas infrastructure investors can continue to justify taking on the risks inherent in investing in the expansion of the existing gas infrastructure and the development of a new, major long-lived network.

Victorian access arrangements

A primary example of the need to reform the current approach to downstream gas industry regulation came in October, as Victoria's ESC handed down a Final Decision on its Review of Gas Access Arrangements for the State. The Final Decision sets access charges for Victoria's gas distribution system from 2003 to 2007.

The AGA believes the Final Decision does not provide strong incentives for gas market expansion in Victoria, or adequately recognise the level of commercial and regulatory risks facing gas distribution businesses. Although the ESC took a positive step in allowing some access charges to rise so that

prices moved to a more sustainable level, this approach was not applied across each of the gas distributors in the State. Additionally, a significant flaw in the Final Decision is an unrealistic set of assumptions about the risk characteristics and actual cost of capital of Victoria's gas distribution businesses. The determined regulatory cost of capital (6.8%) is the lowest ever set for any gas distribution business in Australia. This may act as a significant impediment to new and ongoing investment in gas distribution networks.

Some aspects of the Final Decision also appear to ignore the key findings of the Productivity Commission's Review of the National Access Regime (see below), particularly a central conclusion that regulators should not be overly ambitious in seeking to determine the efficient costs of regulated businesses, and the potential for regulatory failure that such an approach risks.

Productivity Commission Review

The final report of the Productivity Commission's Review of the National Access Regime was released by the Federal Government in September. Both the Commission and the Government (outlines in its interim response to the final report) have recognised the core concern of owners of gas distribution networks and pipelines – that current access regulation has the potential to discourage new and ongoing investment and that change to the current regime is necessary.

They also signalled their agreement that a rebalancing of regulation – including movement towards lighter-handed forms of regulation – is required if the Australian community is to retain the long-term benefits stemming from the provision and maintenance of infrastructure services.

The government's acceptance of one of the Commission's key recommendations – to provide regulators with greater guidance on the objectives of access regulation – was particularly welcomed by the AGA. To effect this the government has proposed the incorporation of a clearer objects clause in Part IIIA of the Trade Practices Act to underline the need to promote investment in essential infrastructure, and the inclusion of access pricing principles that recognise the need for third-party access prices to adequately reflect commercial and regulatory risks.

National gas access regime

The recent release of the Productivity Commission's final report has also cleared the way for the commencement of a comprehensive review of the national gas access regime (including the National Gas Code). This independent review was foreshadowed by the Federal Government in 2000, and was contingent upon the completion of the Review of the National Access Regime and the finalisation of the first round of Access Arrangements under the National Gas Code (which set third-party access to gas pipeline and distribution networks).

The review is now likely to proceed in 2003, along with the further consideration of specific mechanisms to facilitate new investment in gas distribution and pipeline infrastructure. The AGA is hopeful that the review will assist in improving those aspects of the regime that are discouraging investment in new and existing downstream gas infrastructure.

Greenfields developments

During the past year, the ACCC worked on the development of a Greenfields Guideline for Natural Gas Transmission Pipelines. A draft of the guideline was released for public comment in June.

The draft guideline seeks to:

- address the perceptions of regulatory risk regarding greenfields investment;
- demonstrate the flexibility of the regulatory framework;
- identify methods for dealing with project-specific risks; and
- assist prospective service providers to evaluate the likely regulatory outcomes for potential or proposed greenfields projects.

The AGA, however, is not totally convinced that the guideline adequately addresses the concerns of regulated gas businesses with regards to the regulatory framework and its application. It believes that the guideline largely only represents an attempt to defend current regulatory approaches, rather than address regulatory deficiencies which have been identified by the Productivity Commission, regulated businesses and other energy market decision-makers.

It is anticipated that the guideline will be finalised in the first half of 2003.

Meanwhile, the deficiencies of the current regulatory regime with regards to encouraging greenfields investment was emphasised during September, when the Tasmanian Government announced that a competitive tender process, carried out under the National Gas Code for the development of a gas distribution network for the State, had failed to attract any conforming bids. The government partly blamed the failure of the tender process on the Code, saying it was clearly not workable, particularly for large-scale greenfields investments. Since then, more fruitful negotiations outside this framework have been occurring.

The year ahead

Looking to the coming year, the AGA believes that 2003 holds some opportunities for the downstream gas industry, particularly with regards to the development of the National Energy Policy and the review of the national gas access regime.

Next year we will continue to argue for government policy and regulatory approaches that encourage the expansion of Australia's gas distribution and pipeline network, and increase the uptake of natural gas in the industrial, commercial and residential sectors – after all, such developments would deliver significant benefits to many Australians.

The Australian Gas Association 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. For more information regarding AGA, you can visit* **www.gas.asn.au

Industry call for government action

Buoyant global crude oil prices and recent successes in gaining gas sales contracts to Asia after long lead times may mask the need for urgent energy policy action in Australia to address emerging petroleum industry issues. *Barry Jones*, Executive Director of the Australian Petroleum Production and Exploration Association* (APPEA) reports.

The challenges facing the upstream oil and gas industry in Australia are two-fold. The sector needs to find more oil to replace its rapidly declining supplies of liquids (see **Figure 1**) and it needs to find new markets for its abundant supplies of natural gas. In some respects the two challenges are interrelated. In the longer term, using more gas (directly and indirectly) as a transport fuel will be an option that needs to be implemented if the country fails to find adequate additional oil reserves and wishes to avoid an increasing import bill.

For many years now Australia has enjoyed a liquid fuels self-sufficiency level in excess of 80% (rising to over 90% in the last couple of years following the coming onstream of the Laminaria field in the Timor Sea). Government forecasts of production and reserves suggest that this level of self-sufficiency will drop rapidly over the next eight years to at least 50%, possibly lower (see **Figure 1**).

Production decline

The key liquids developments over the last couple of years, such as Legendre and Simpson, coupled with pending projects, including Angel, Bayu Undan, Enfield, Laverda, Woollybutt and Yolla, will not offset declining production in the mature Gippsland Basin and in the Laminaria project. Recent discoveries in the Perth Basin, while valuable, do not effect the overall self-sufficiency picture either.

The high overall production levels of recent years have, to some extent, masked the fact that the larger, more prolific fields in Australia are in a state of production decline. Furthermore, the new finds that have been made have, for the most part, been relatively small with a shorter production life (see **Figure 2**).

Policy implications

There are a number of major national policy implications for Australia resulting from this production decline. These include:

- an increased risk of supply disruption,
- a decline in Commonwealth and State taxation revenue,
- a worsening of the balance of payment, and
- an increased risk of environmental damage as a larger proportion of Australia's liquids requirements is imported via an ageing shipping fleet.

The supply risk will arise because of the volatile political situation in the Middle East (the major alternative supply source) and instability along various supply routes to Australia (for both crude and petroleum products). The age of the Australian refining industry, together with its relatively small production units and its growing reliance on imported crude as a base fuel, mean that the risk of refinery closures is high. If such closures occur security of supply could be severely compromised.

Some of Australia's older oil fields have been contributing in excess of $2bn/y to government coffers in the form of profits based production taxes. However, their replacement domestic production fields will pay taxation contributions that are considerably lower than this, leading to a decline in Commonwealth and State taxation revenue.

Furthermore, given that production is forecast to fall from about 720,000 b/d in 2000 to between 200,000–500,000 b/d in 2010, Australia faces an additional import bill in the range of $4.5–$8.6bn/y – assuming longer term average oil prices in the low $20 range. At least half of this increase in the import bill will come in the period to 2005 and is probably unavoidable. The possibility that increased export gas sales may offset part of this bill will not arise until later in the decade.

Gas challenges

On the gas side there are, in effect, two challenges to be met. The first relates to the gas export market where Australia is one of the largest and most reliable exporters of LNG in the world. The past year has seen the North West Shelf joint venture commence construction of its fourth LNG train on the Burrup Peninsula in Western Australia and secure a 25-year LNG export contract to Guangdong Province in China – the first such contract. It is likely that this sales contract will eventually lead to the construction of a fifth LNG train.

In addition to these developments, a number of major new projects are under consideration, including:

- an LNG plant planned for Darwin based on gas from the Bayu Undan field in the Timor Sea;
- an evaluation of a major gas development (the Gorgon project) offshore Western Australia that may have an LNG plant or a gas-to-liquids project associated with it; and
- evaluation of a floating LNG facility as part of the Greater Sunrise Project in the Timor Sea.

Carnarvon Basin gas (including output from projects such as Angel and Linda/Rose) may also have potential markets in a methanol plant currently under consideration for the Burrup Peninsula and a fertilizer plant being considered for the same location.

A highly competitive situation also exists in the domestic gas market where strong economic growth coupled with the completion of a number of major interconnector gas pipelines and the imperatives of greenhouse gas policy are creating market opportunities.

In the southeast of the continent ExxonMobil has just completed a major 3D seismic survey over the Gippsland Basin at a cost of $300mn. Gas developments are under construction at Patricia/Baleen in the north Gippsland Basin and at Yolla in the Bass Basin (between Tasmania and the mainland). Development proposals for supplying gas into the southeast Australian market are also being evaluated in the Otway Basin offshore Victoria. Furthermore, there is an option to develop gas from the Bonaparte Basin (for

example via the Blacktip project) to supply northern Australian markets.

Meanwile, coal seam methane developments are underway in the Sydney Basin and at several locations in the Bowen and Surat Basins in Queensland. Further development is planned for the Narrabri region of New South Wales.

The possibility of supplying gas to southeast Australia via north–south pipelines is being evaluated in relation to gas from Papua New Guinea and from the Timor Sea. Both these projects are also looking for market opportunities in minerals processing projects in northern Australia. In the longer term, the possibility of a west–east trans-Australia pipeline cannot be discounted given the vast (approximately 100tn cf) gas resources that exist in the Browse and Carnarvon Basins and the possibility that these resources will be enhanced in the near future as appraisal drilling is completed in relation to the Jansz discovery.

Call for government action

However, in order to meet oil production and gas market challenges the Australian Government needs to take action on a number of policy fronts.

In relation to oil, a major exploration drive needs to be facilitated with a particular emphasis on high-risk frontier areas, particularly in the deepwater offshore. Pre-commercial resource assessment work has to be maintained and enhanced, requiring additional funding for the relevant government agency, Geoscience Australia, and taxation incentives to encourage industry to undertake high-risk, speculative seismic surveys.

Complex, overlapping and time-consuming approval processes need to be streamlined. There is currently a quagmire of approvals relating to the environment and indigenous land rights that must be addressed urgently. These processes are delaying developments for considerable periods and also absorbing (in unproductive activities) significant funding that would otherwise go to exploration.

The company and production taxation systems need to be changed as well, in order to make it more attractive for both Australian and overseas capital to flow into the country's oil exploration companies. A national parliamentary inquiry into impediments to resource exploration was recently initiated. The Australian oil and gas industry has put forward proposals to the inquiry and directly to government – including a five-point package of taxation proposals designed to make investment in gas and oil proposals commercially more attractive.

Also, in relation to the domestic gas market, treaty arrangements with the new government of East Timor need to be ratified no later than the end of 2002 in order to allow the Bayu Undan project and its associated proposed LNG development to proceed. Unitisation arrangements for the Greater Sunrise development also need to be urgently completed.

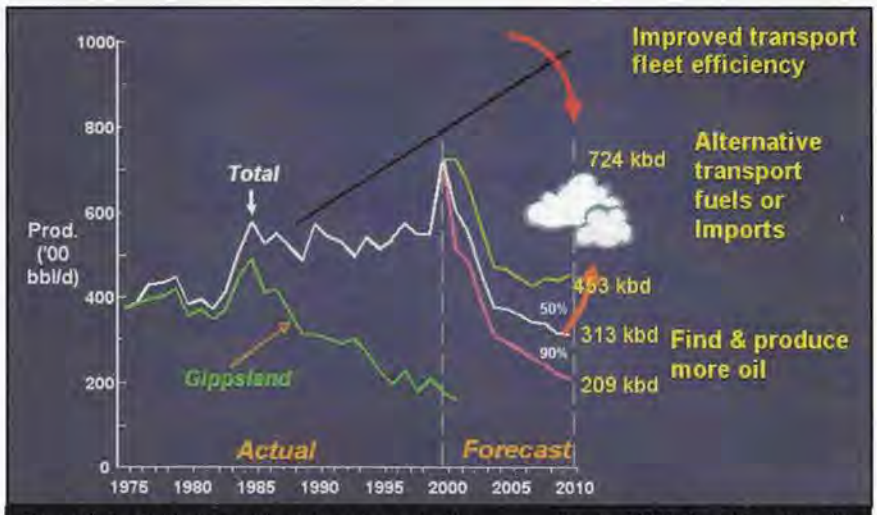


Figure 1: Australian oil and condensate production. *Source: APPEA, Geoscience Australia*

Regulatory problems in the east coast energy market need to be rectified as soon as possible and the role of gas in resolving greenhouse policy issues needs to be clarified. In the latter context, a clear fuel substitution strategy needs to be implemented, particularly with respect to transport fuels and primary energy for Australia's primarily coal-fired east coast electricity generation system. The greenhouse emission intensity of this high-volume electricity market is a major cause of concern in a greenhouse policy response context.

Opportunities ahead

The Australian upstream oil and gas industry believes that there are still significant oil reserves to be discovered and developed in Australia and that there is an opportunity to gain a greater gas market share both domestically and in the rapidly expanding Pacific Basin market. While some policy matters need to be addressed, the industry believes the national government recognises this and is moving to address these issues.

For more information about APPEA, the national representative body for Australia's upstream gas industry, visit* **www.appea.com.au

Figure 2: Most new finds that have been made in Australia have, for the most part, been relatively small with a shorter production life

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
Baleen (Bass Strait)	OMV	gas	2002/3	–	100	–	–
Bambra	Apache	gas/cond	2004	0.7	30	–	wellhead plat via Harriet
Brecknock/Scott Reef	Woodside	gas/cond	2005+	228	18,400	–	poss LNG development
Chrysaor*	Wapet	gas	2012	40	2,600	150	*part of A$10 bn project
Dionysus*	Wapet	gas	2010	–	350	–	poss LNG development
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
Echo-Yodel	Woodside	gas/cond	Jan-02	37 (cond)	400	200	2 subsea via Goodwyn A
Enfield (WA-271-P)	Woodside	oil/gas	mid 2005	30.7	–	–	2 subsea to Barrow Island
Evans Shoal	Shell Australia	gas	2005/9	–	10,500	–	Darwin LNG, 7.5 mn t/y?
Gypsy/Rose/Lee	Apache	oil/gas	2002/3	7	150	–	wellh'd plat to Varanus Is
Golden Beach	Santos	gas	2004	–	50	–	–
Gorgon*	Chevron/Texaco	gas	2012	14 oil,50 cond	9,600	–	poss 6mn t/y LNG plat
John Brookes	ExxonMobil	gas/cond	under eval	–	–	–	–
Kipper (Gippsl'nd Basin)	ExxonMobil	oil/gas	2004	13	575	263	–
Laminaria Phase 2	BHP	oil	2002	21	–	130	2 horiz wells. 65kb/d peak
Laverda	Woodside	oil	2005	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	2003/6	26	260	–	FPSO and subsea
Minerva/La Bella (Otway)	BHP	gas	2004	1	360	–	subsea or monotower
Nappamerri Trough	Santos	gas	end-2003	–	–	–	–
Nasutus	Apache	oil	under eval	–	–	–	–
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	2005+	–	8,000	4,700	supply proposed LNG?
Searipple	Woodside	gas/cond	2005+	–	50	–	with Perseus via N Rankin
Simpson, Carnavon Basin	Apache	oil	–	–	–	–	21,000b/d from 3 wells
Spar*	Chev/Tex/Ampol/Shell	gas	2012	–	–	–	–
Stag	–	–	–	50	–	–	–
Tenacious	OMV	oil	under eval	5	–	42	tie-back to Jabiru
Tern/Petrol B'nap'te Glf	Santos	gas	2005	–	3,000	–	platform or FPS
Tidepole	Woodside	gas/cond	2013	14 (cond)	420	–	–
Vincent (WA-271-P)	Woodside	oil	2005?	117.4	–	–	via Enfield facils
West Tyral Rocks*	Wapet	gas	2010	19 oil,21 cond	1,600	–	–
Wilcox	Woodside	gas/cond	2010	–	300	–	to Goodwyn or Echo-Yodel
Yolla (Bass Basin)	Origin Energy (ex Boral)	oil/gas/cond	2005	45 cond	300	240	platform 49mn cf/d,5kb/d
KEY DISCOVERIES							
Lynx/Vega	Woodside	gas	–	–	–	–	–
Cornea WA-241-P	Shell	oil	–	500?	–	–	–
Bellerphon	Apache	oil	–	200?	–	–	–
Jacaranda Otway Basin	Boral Energy	oil	–	–	–	–	–
Blacktip	Eni	gas	–	–	1,000	–	potential 2.53mn cm/d
Tregony (PEP 153)	Santos	gas	–	–	–	–	potential 10–15 mn cf/d
Thylacine	Woodside	gas	2006	–	600–1,000	–	–
Geographe	Woodside	gas	2006	–	400–600	–	–
East Pilchard	Esso Australia/BHP	gas	mid-2003	–	–	–	–
Sub Total				**1,498**	**68,895–69,495**	**5,725**	
TIMOR GAP-ZOCA							
Greater Sunrise**	Shell	gas/cond	2006+	300	9,160	–	with Bayu Undan/float LNG
Laminaria East	BHP	oil	–	–	–	–	close to Buffalo field
Bayu/Undan	Phillips	gas/cond	4Q-03/1Q-04	404	–	1,696	3 platforms, Ph1 liquids
Bayu/Undan	Phillips	gas/LNG	2006	–	3,400	–	phase 2 LNG/pipe Darwin
Jahal	BHP	oil	–	–	–	–	–
Sub Total				**704**	**12,560**	**1,696**	
GRAND TOTAL				**2,202**	**81,455**	**7,421**	

**Greater Gorgon comprises Gorgon, Chrysoar, Dionysus, West Tyral Rocks and Spar fields*
***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*

Opito-1 well targets Kapuni sands along north Taranaki coast, North Island

Global interest in New Zealand E&P potential

New Zealand is attracting increased petroleum exploration investment as the country's resource potential becomes more internationally recognised, writes *Lindsay Clark*, Editor of *New Zealand Petroleum News*, published by the New Zealand Ministry of Economic Development's Crown Minerals Group.

In 2002 New Zealand's ranking among the world's most attractive petroleum exploration destinations moved up to a record 14th place, five places higher than last year according to the latest IHS Energy Group's PEPS international survey. The increase in exploration activity has been prompted by discoveries of both oil and gas over the past four years. It has been further encouraged by an awareness that supplies of natural gas are running short, while in oil New Zealand's self-sufficiency has fallen to 31% from about 50% a decade ago.

The finding of the substantial Pohokura gas condensate field at the centre of the Taranaki Basin, New Zealand's current oil and gas producing area, has helped raise explorers hopes of further such finds. Other new oil discoveries have been made in both offshore and onshore Taranaki.

Early estimates of the Pohokura field put its reserves at over 900bn cf of gas and over 50mn barrels of condensate. These figures are set to be revised after final Pohokura onshore and offshore appraisal wells have been drilled at the close of 2002.

Over the past two decades the large Maui gas condensate field in offshore Taranaki has dominated the New Zealand energy scene, providing low-cost gas to the more populous North Island. Condensate and oil from Maui also account for a large share of domestic liquid fuel production. However the field owners announced in 2001 that Maui could be depleted by mid-2007 instead of the previously estimated 2009.

Explorers are expecting gas prices to rise to meet the shortage in demand. New Zealand to date has always produced 100% of its domestic gas needs. In addition almost 40% of gas produced is converted at two Methanex Corporation plants to methanol and exported. These New Zealand plants produce 8% of the world's chemical grade methanol. With a threat of future lower gas supply, production from these plants may be cut back.

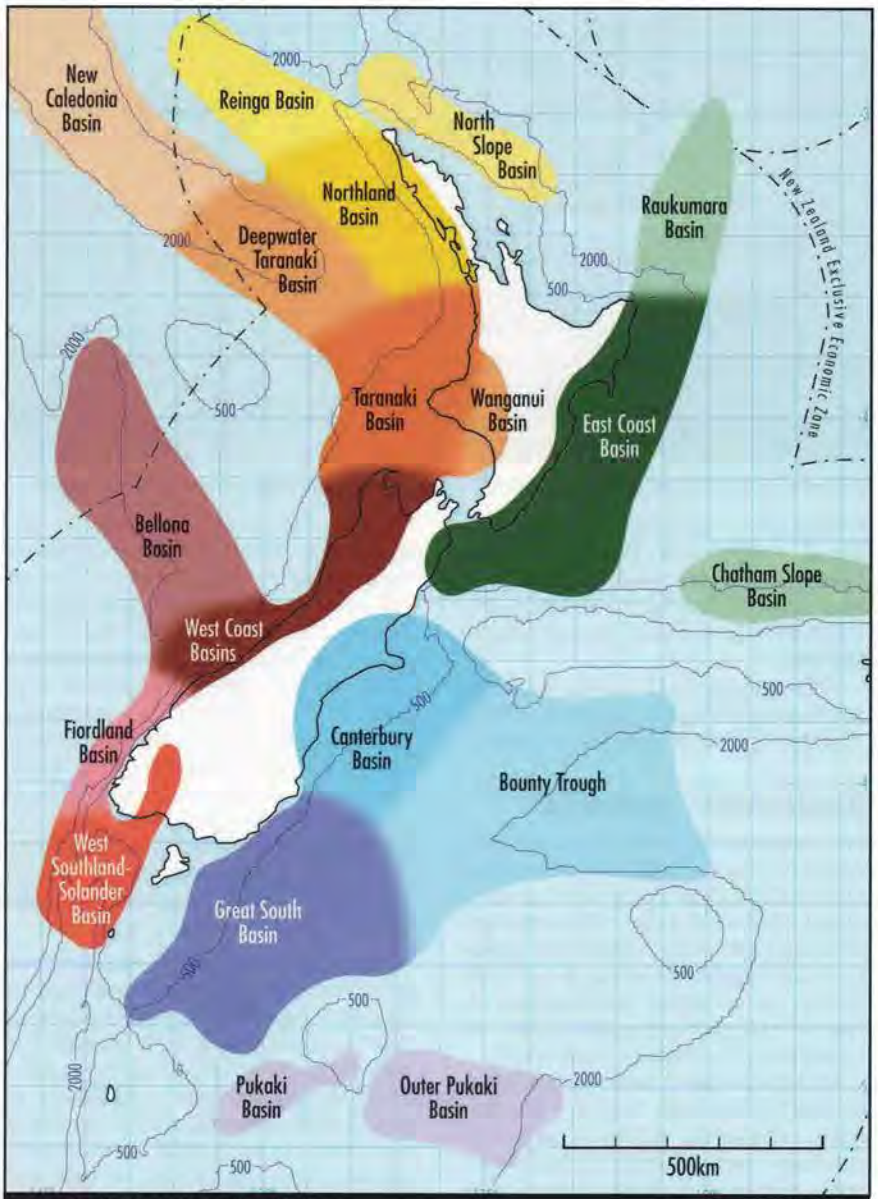
When the Pohokura field comes onstream by 2006, the gas produced is expected to only partially replace Maui gas.

Keen European interest

European-based companies have been increasing their involvement in New Zealand over the past year, particularly in the search for oil and gas in offshore Taranaki Basin. Shell, following its takeover of the largest New Zealand explorer Fletcher Challenge Energy in 2001, has continued to take advantage of its stronger footing in the New Zealand market. It now has a majority ownership of the established Maui field and it is the lead partner in the Pohokura field. Shell in 2002 also took up major interests in two exploration permits in offshore Taranaki.

Two other substantial European companies have made investments in offshore Taranaki projects. Austrian energy company OMV Petroleum stepped up its investment in New Zealand in 2002, purchasing a 10% interest in the Maui field. The company has also increased its stake in the Maari oil discovery offshore Taranaki from 30% to 79%, and plans to drill a further Maari appraisal well in early 2003. OMV also has interests in three other offshore permits. New Zealand is a most attractive region, according to Helmut Langanger, OMV's Exploration and Production head. 'Participation in the Maui field paves the way for OMV to establish itself as a significant player in New Zealand.'

German-based Preussag Energie has recently increased its stake in the Pohokura field to 36%, as well as investing in new onshore Taranaki exploration.



New Zealand's sedimentary basins — *Source: Crown Minerals*

More Australian-based exploration companies are now investing in New Zealand. Among new entrants in 2002 have been Tap Oil, Magellan Petroleum, Bounty Oil & Gas and Hardman Resources. A number of other Australian companies already exploring in New Zealand — such as Origin Energy and Australian Worldwide Exploration – have also stepped up their investment.

North American independents have been particularly attracted to New Zealand, with 15 companies from the US and Canada now involved in exploration in the country, mostly in onshore acreage.

New Zealand-based companies have also made new investments in 2002. The largest, Todd Energy, is participating in its biggest ever exploration programme this New Zealand summer involving five offshore and three onshore wells. Todd also bought two neighbouring onshore Taranaki oil and gas fields – McKee and Mangahewa – and raised its interest in the Pohokura field development.

Field	Operator	Oil reserves (mn b, est)	Gas reserves (bn cf, est)	Cost (est)	Start-up
Pohokura	Shell-Todd	53	900	$350–450mn	2006
Rimu	Swift Energy	10	40	–	2002
Maari	OMV	25	–	$170–300mn	–

Table 1: New Zealand fields under appraisal

The new Rimu oil and gas production station, onshore south Taranaki, North Island

Meanwhile, new entrant Auckland-based Greymouth Petroleum purchased the Kaimiro field, took a major interest in the Ngatoro field and is also involved in a number of exploration permits.

Wellington-based Indo-Pacific Energy is one of the busiest explorers, with a 15-permit portfolio over three basins.

Exploration potential

The continental shelf around New Zealand is huge — the area of the shelf within its exclusive economic zone is about 20 times the size of the country's land area (see map). Within this region there are eight sedimentary basins with known or potential hydrocarbons, as well as several deepwater basins. All basins have an offshore component.

All New Zealand petroleum production so far has been from the Taranaki Basin, the most explored province. However, even Taranaki is only moderately explored compared to similar sized basins worldwide. The rest of the country is under-explored.

Current developments

Pohokura – Development planning for the Pohokura gas condensate field, discovered in 2000 in offshore Taranaki, is well advanced. An offshore appraisal is currently being drilled at the northern end of the field about 12 km from shore. A 5,500 metre extended reach appraisal well from onshore is also being drilled. The field is likely to be operated from shore with two or three small wellhead platforms offshore. The production plant will be built alongside the largest of Methanex's methanol plants, which lies alongside the new field.

Pohokura reserves, based on results from the first two wells, are estimated at 900bn cf of gas and 50mn barrels of condensate. Based on current project planning, the field is due onstream by 2006 at a cost of US$350–450mn.

Maari – The Maari offshore oil discovery was found in 1998 in offshore Taranaki Basin almost 40 km south of the Maui field. Recently OMV became operator after buying out Shell's previous 49% interest. OMV now holds a 79% interest in the Maari permit, with Todd Energy holding the remaining 21%. An appraisal well, Maari-2, will be drilled by OMV-Todd in early 2003. Maari reserves are currently estimated at approximately 25mn barrels, although similar structures nearby may eventually boost this figure. Maari development cost was earlier estimated by Shell at US$170–$300mn.

Rimu – A new onshore discovery, the Rimu oil and gas condensate field in southern Taranaki, was first made in 1999 by Texas-based Swift Energy. The field currently has an estimated reserve of 10mn barrels of oil and 40bn cf of gas. The Rimu mining permit came into production in early 2002. The main oil-bearing formation found to date has been the Tariki Sandstone, although a feature of the field so far has been the location of multiple zones of oil and gas. A zone of shallow oil, only 1,100 metres deep, was also found by Swift Energy in its neighbouring Kauri prospect where drilling began in 2001.

Other exploration – The onshore area of the Taranaki Basin has been the main area of exploration in 2002, with wells targeting three main types of formation – the Oligocene Tariki Sandstone play in the Tarata Thrust Zone (Rimu, Tariki fields); the Eocene Kapuni sands play along the north Taranaki coast (Pohokura, Mangahewa and McKee fields); and the Miocene Mt Messenger oil plays found in central Taranaki (Ngatoro and Kaimiro fields). The Mt Messenger/Moki oil plays are also being sought in parts of south Taranaki.

In offshore Taranaki wells are planned in early 2003 to the north of the basin by Conoco in the Miocene Mangaa Formation and by New Zealand Oil & Gas in the Eocene Tui prospect close to the Maui field.

Investment opportunities

Opportunities for new investment in the New Zealand petroleum industry are greater than they have been for many years.

- New Zealand's first deepwater petroleum permitting round has been launched with a five-block Deepwater Taranaki Basin round off the west coast of the North Island on offer. The unexplored 42,000 sq km area in waters 200 metres to 1,800 metres deep is adjacent to the highly productive Taranaki Basin. The deepwater basin will be allocated by staged work programme bidding. A total of 6,208 km of non-exclusive 2D reconnaissance seismic data, tied to eight wells near the shelf edge, was acquired by TGS-Nopec in 2001. Interpretation of the new data has revealed an exciting new play, a Late Cretaceous delta approximately 100 km long and 2,000 metres thick that appears to be rich in source rocks. There may also be an Eocene sandstone play. Applications close on 30 September 2003.
- A five-block permitting round over the predominantly offshore Canterbury Basin off the east coast of the South Island, was opened in November 2002 with applications closing in May 2003. The permitting round covers a total area of 31,000 sq km. Canterbury Basin is little-explored, but is considered highly prospective because of the proven existence of an effective petroleum system and the previous discovery in the 1980s of gas condensate in the Galleon-1 well, judged non-commercial at the time.
- Another permit round will be notified in 2003 over an extensive offshore and onshore area of the Taranaki Basin. The area will include the highly prospective Northern Graben.
- Exploration permits can also be issued under the Acceptable Frontier Offer method that allows explorers to submit bids at any time over virtually any unpermitted area of their choice.

Further information on the permitting rounds can be obtained from the Crown Minerals website at **www.crownminerals.govt.nz**

The recent discoveries, the growing exploration potential, the stable political system and excellent fiscal regime all add up to New Zealand becoming a more attractive place to explore.

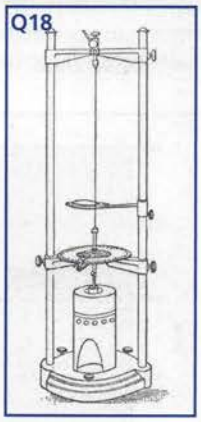
Petroleum review christmas quiz

The lucky prizewinner of *Petroleum Review*'s annual Christmas Quiz will receive a bottle of champagne while the two runners up will each receive a £15 voucher that can be redeemed against any IP product (excluding membership fees). So, get your thinking caps on and *Good Luck!*

(Telephoning the IP Library and Information Services for the answers is strictly prohibited... you are on your own!)

1. Who, in 1909, patented the 'rotary drilling bit'.
2. As Redwood is to the UK and Saybolt to the US, who is to Germany?
3. Which of the 'Seven Sisters' has retained her maiden name?
4. What is the name of the process in which natural or synthesis gas is converted into liquid fuel?
5. North Sea oil was formed during the Cretaceous period. When was this?
6. 

   (b) In which decade did it first appear in UK advertising?
7. What caused the sinking of the Shell oil tanker *Goldmouth* in March 1916?
8. Which country or area is attributed with having the greatest volume of natural gas reserves?
9. Who developed 'Kerosene' and gave it its name?
10. Albert Fall, Harry Sinclair and Edward Doheny participated in various US Senate Committee enquiries and criminal trials. What name is given to their activities?
11. If John Browne will forever be synonymous with 'Beyond Petroleum', then this man should equally be associated with 'Before Petroleum' – who was he? (© BP plc, 2002)
12. Daddy made a fortune from oil; the boys lost one.
    (a) Who was daddy? (b) Who were the boys? (c) How did they lose it?
13. In 1967, Prime Minister Harold Wilson ordered the Fleet Air Arm to attack an oil tanker lying off the Scilly Isles. Why?
14. Imported in 1964, the UK was the world's first customer for this fuel. What was it?
15. By what name is CH_4 more commonly known?
16. Which oil company came into existence on 1 January 1976 and disappeared during the spring of 1985?
17. What is the name of the world's largest oil tanker?
18. What was the piece of laboratory apparatus on the right used for?
19. Which is the odd bird out – Dunlin, Cormorant, Eider, Avocet, Tern, Gannet, Bittern, Petrel, Curlew?
20. The *SeaRiver Mediterranean* is better known by its former name. What was it?



Please send your completed entry form to The Editor, *Petroleum Review*, The Institute of Petroleum, 61 New Cavendish Street, London W1G 7AR, UK or F: +44 (0)20 7637 0086. Remember to include your contact details, including name, membership number, tel/fax numbers and e-mail address.

Alternatively, an online link to the quiz can be found on the *Petroleum Review* home page, part of the IP website at *www.petroleum.co.uk* – just fill in the details and hit return.

Closing date for entries is 6 January 2003. Those with the most correct answers will be placed in the prize draw. The three lucky winners will be announced on the IP website by the end of January. Their names will be printed in the February issue of *Petroleum Review*, together with the answers.

An industry unleashed by technology?

Aligning information technology (IT) and data management strategies with business needs is now more critical than ever, reports *Tony Wood*, Global Marketing Manager for IBM Chemical and Petroleum Industries.*

The upstream petroleum sector appears to be at a crossroads. Today's uncertain and volatile crude prices coupled with a more complex global business environment are changing industry dynamics. At the same time shareholders are becoming more demanding, not only looking for increased production and underlying reserves growth, but also demanding a return on their investment that keeps up with long-term market performance.

In meeting these demands the upstream petroleum industry faces a number of specific challenges:

- production growth – improving efficiency and capability to recover increasing volumes of oil and gas;
- planning for and managing the 'big crew change' as the ageing workforce leaves the industry;
- which results in a need to 'institutionalise', share experiences and knowledge management.

The adoption and implementation of technology, both oil field and information technology (IT), continues to be a critical success factor in meeting these challenges. Information technologies, as discussed below, can assist the upstream industry in not only meeting the challenges already identified, but can also provide a firm foundation for continued transformation.

Unleashed by technology?

The upstream oil and gas sector has long advocated and depended upon advanced technologies, both oil field and IT. In the case of IT, technologies such as high performance computing, storage and sophisticated algorithms have helped the industry be more successful in both finding and extracting oil and gas deposits through the application of 3D seismic and visualisation techniques. The net effect has been to dramatically reduce finding and lifting costs (see **Figure 1**).

There is a widely held opinion that IT technologies continues to be extremely important today and will be even more so in the future. As noted by Salomon Smith Barney:[1] 'Seismic/CAEX (computer-aided exploration) technology continues to have the greatest impact on the industry, an observation that has consistently been evident since the wider use of 3D seismic began in the early 1990s. This year, a record 67% of respondents cited seismic and related technologies as having the greatest impact on their spending plans.'[1] Industry commentators have also recognised the importance of IT, citing that the 'use of integrated information technology solutions can improve productivity to replace about 20% of the missing employee base'.[2]

Whilst the love affair with IT for its own sake has fallen out of favour with financial analysts, pundits and the general public following the abrupt end of dot.com companies, the upstream industry is well positioned to take advantage of current IT technologies that have been developed to support it, particularly as the industry is:

- data and information intensive;
- truly global;
- has a large variety of business relationships;
- is extensively interconnected;
- with supply chains and value chains ripe for integration.

So if the upstream industry is poised to take advantage of developing IT technologies what are these technologies and what their impact will be on the industry?

High performance computing, Linux, portals, middleware, wireless, pervasive – there are a myriad of technologies available today. The technologies that are going to have a major impact on the upstream industry are those that recognise that information and knowledge are the key requirements, not just data. Those applications that address issues such as complex integration of fragmented legacy systems with new applications can provide new flexibility. These can not only respond to changing business needs but also take advantage of and incorporate new and emerging technologies. But, most importantly, IT technologies must deliver real and tangible business value – it is what separates viable technologies from the rest.

When one looks at IT in the context

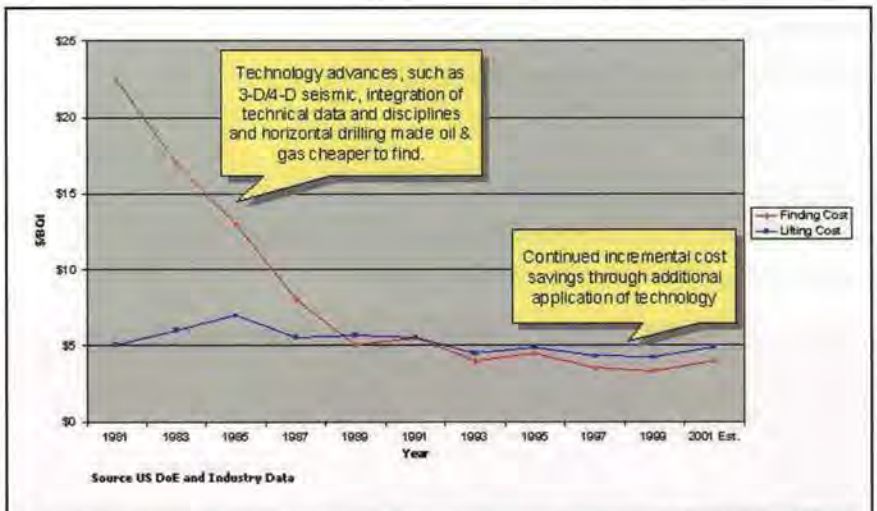


Figure 1: Worldwide finding and lifting costs ($/boe) *Source: US DoE and industry data*

of business value, five key areas emerge, which are illustrated in **Figure 2**.

Analysis, modelling and simulation – The ability to model, monitor and manage reservoirs in real time is required to maximise production and minimise expense. This will require superior reservoir models that can, for instance, provide more accurate modelling of horizontal multi-lateral well effects and near well bore effects. Models that can facilitate the coupling of the simulator with dynamic reservoir characterisation features, such as depletion-induced rock stresses or real-time reservoir and well bore monitoring. These requirements will in turn require high-fidelity subsurface definition, implying more complexity along with better accuracy and faster processing. Ultimately, the goal will be the ability to interactively manage reservoir performance, in real time, at the well, the surface facility and at the field level, utilising production and other data as appropriate.

The technology requirements to satisfy this need include quality algorithms, improved data sharing, more bandwidth and lots of computing power. Many of these technology requirements are being met with the development of modelling solutions from companies such as Landmark Graphics, as they utilise Linux cluster technology running on cost-effective platforms, such as IBM's intellistation workstations.

Visualisation – Reservoir characterisation is as much an art as a science, utilising the insights and experience of a range of professionals. The ability to share a common view of the reservoir, together with the assumptions used in its characterisation, leads to better decision making about the likely behaviour and optimal way to effectively maximise production. Hence the underlying business requirement is to make informed business decisions and get sub-surface results faster, better and cheaper. Increasingly this will need to be outside the 'cave' and in a more geographically dispersed collaborative environment.

Here the technology requirements are of course the visualisation software and hardware – ie visualisation rooms, and of course lots of computing power to display, render and animate the model as appropriate. To support real-time collaboration across a network such as the Internet, requires robust, secure and scalable infrastructure, together with the necessary bandwidth. The development of portals which are based on technologies such as WebSphere, which allow collaborative data and information sharing, will

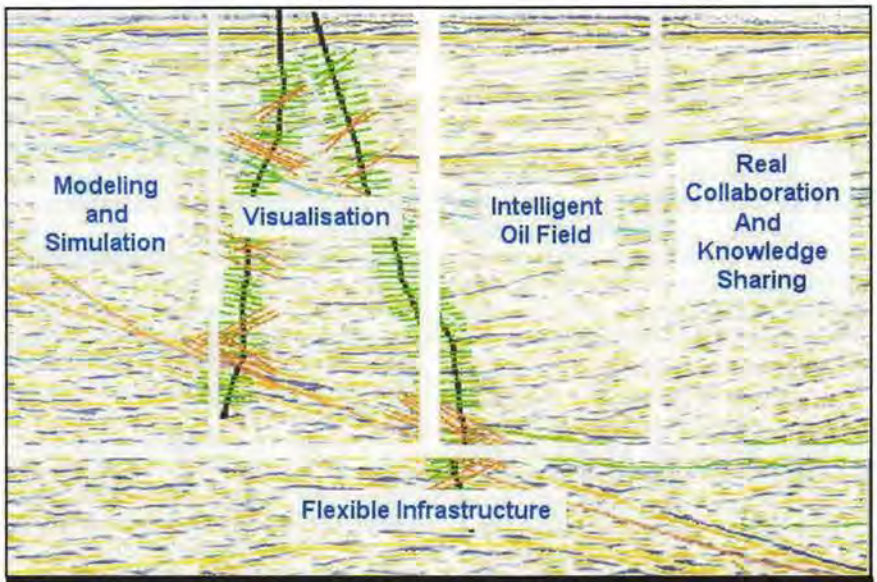


Figure 2: There are five key areas in IT in the context of business value

be a pre-requisite. Additionally, the individual workstation will also need to have the appropriate processing and visualisation capability – here again Linux is set to make dramatic inroads into the traditional proprietary workstation environment, running on 'cheap' hardware such as the intellistation and utilising high resolution screens such as IBM's T221, which can display nine million pixels.

Intelligent oil field: automation and remote operation – Smart wells and electric oil fields are currently being piloted by a number of oil companies including the majors such as Shell. The goal of these initiatives is to link the field development process – ie the sub-surface characterisation – to the means of production, in this instance the well, in order to maximise business value. Ultimately, however, business value will be maximised when real-time information and knowledge on all field assets – from horizon to export pipeline – is available and used to make production and reservoir management decisions, meeting anticipated market and company requirements. Linked with the automation and remote operation of facilities, this becomes the intelligent oil field. (See **Figure 3**.)

The underlying technology requirements are fairly straightforward – intelligent gateways collect and distribute the data from pervasive and SCADA devices through the use of a message broker such

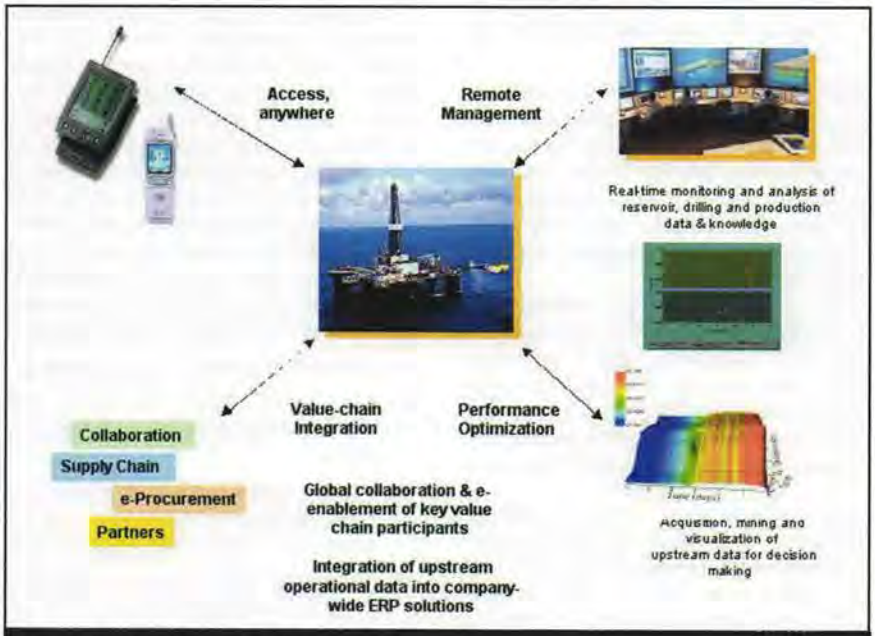


Figure 3: The 'intelligent oil field'

as MQseries. Workflow management tools such as CrossWorlds can link the data to business processes. However, the success of the intelligent oil field will not be predicated on collecting a myriad of time series data points from the well, the production facilities etc. Instead, the real business value will come from turning this data into meaningful information upon which decisive action may be taken. Technologies such as data mining and business intelligence can help the decision part of taking decisive action:

- *Workover scheduling* – Producing wells periodically need workovers to keep them producing efficiently. Data mining can be used to help optimise the workover schedule for a field by predicting the likelihood of production problems developing within, say, the next three months. By performing maintenance on high-risk wells before they actually develop significant problems, production interruptions can be reduced. This constitutes an 'early warning system' for well maintenance.
- *Production performance forecasting* – Production performance forecasting is necessary for many purposes such as regulatory compliance and property valuation. Forecasts of oil and gas (and water) production rates are often developed through field studies entailing reservoir simulation modelling. Data mining has the potential to enrich field studies by predicting production profiles for relatively new wells. Where there is limited information on early performance, data-based on the performance of older wells with mature production histories, can be used to calibrate and corroborate early performance characteristics such as rock fluid properties.

Well log analysis is used for correlation of producing zones, facilities and utilities performance profiling for preventative maintenance – there are many areas where such approaches could provide real benefit and help both reduce costs and improve recovery from the reservoir.

These tools linked to collaborative networks through portals, supported by life cycle databases and engineering tools, also provide the basis for managing the asset from the exploration stage through design and construction to operation and final decommissioning.

Real collaboration and knowledge sharing – The need for collaboration and knowledge was highlighted in the preceding session. It is doubly important, as it provides one of the key mechanisms for institutionalising key industry knowledge, which needs to be captured and disseminated before the 'big crew change' occurs

Facilitating collaboration and knowledge sharing is not just a technology issue. The key challenges relate to cultural, organisational and behaviour issues such as encouraging and rewarding information together with knowledge exchange. For the upstream business in particular, there is also the issue of the project asset based mentality – ie 'I can see the benefit of knowledge sharing, however I have a tight project deadline and I am not willing to trial these new technologies on my project.'

That said, IT technologies are available to support collaboration and knowledge sharing. The utilisation of community portals (a set of employee centric services delivered through an integrated desktop environment) is becoming widespread, supported by tools such as Lotus Dynamic Workplace, which will improve operational efficiency and reduce costs from e-enabling key business processes and facilitating sharing of best practices between operating units. These tools can also support and facilitate mobility and diversity through allowing extended teams to interact through more 'channels' – ie wireless, mobile phones, Internet browsers etc – to support an anytime, anyplace, anywhere culture that is becoming a pre-requisite in the global upstream business environment. This will help facilitate real-time, online communities around common skills, projects, assets or indeed business areas.

One of the major solution areas that will fully leverage these technologies will be Asset Life Cycle management, or ALM (also known as Product Life Cycle management or PLM in discrete manufacturing industries), where the key business drivers are to deliver the lowest total lifecycle cost coupled with the earliest revenue streams. A collaborative environment that supports the differing needs and participates of the various stages of the life cycle – ie conceptual and detailed design, construction installation and maintenance, production operations and eventual decommissioning – is critical. Key collaborative elements that IT needs to support include:

- Workflow creation and modelling.
- Messaging, both automatic and manual such as Internet relay chat (IRC).
- Alerts, again both automatic and user defined such as alerting when design changes are being proposed.
- The ability to set-up and support virtual communities both on an ad-hoc and more formal basis.
- The ability to support both global and local requirements such as languages, standards and regulations.
- The ability to carry out extensive queries and searches of archives etc.

Flexible infrastructure – the technology foundations – The successful implementation of the technologies detailed earlier and the attainment of the business goals requires a robust, scalable, secure and flexible infrastructure.

Unfortunately, as in most industries, unregulated technology proliferation is the norm. This has led to an overly complex and ineffective infrastructure that does not support the future requirements of the business. Therefore, the challenge is to connect and integrate all of the technologies and information that 'touch' and support the extended team and their associated workflows. An integrated and connected infrastructure will allow the upstream business to connect workflows, stakeholders and partners in a seamless way. (See **Figure 4**.) The infrastructure, becomes a source of value rather than frustration. Such an infrastructure should be based on open standards such as Linux as this helps protect the infrastructure investment from shifts in technology and changes in business model. Additionally a common infrastructure facilitates the implementation of best practices across the extended enterprise and helps ensure a consistency in the way things are done.

Grid computing

One of the challenges the industry will always face, in respect of any investment, is the variability of workload due to fluctuating oil prices. Do you invest in IT for peak production or for a smoothed demand profile from users? IBM has been working on using GRID computing techniques as a way of dealing with this problem.

What is GRID? Consider the Internet as a computing platform, Grid computing links servers, clients and storage across the Internet to dynamically form virtual servers and storage pools to support the creation of virtual organisations, both ad-hoc and formal, to meet specific user needs. For example, originally the Internet let people share or read from the same memory (web pages), then open software protocols such as Java applets enabled people to share software applications to perform web transactions.

GRID computing organises and manages resources from multiple sites to execute large applications. It also:

- Allows transparent access to data in a geographically distributed computing environment with many users working independently.

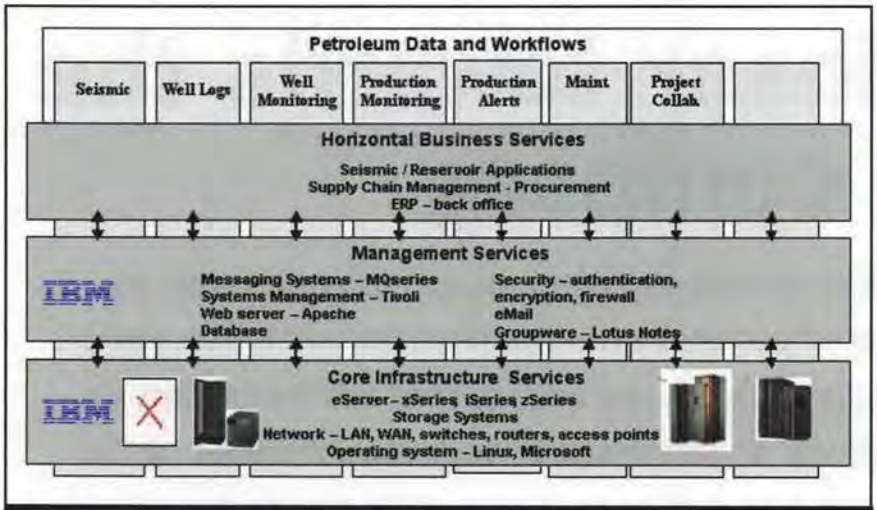


Figure 4: An integrated and connected infrastructure will allow the upstream sector to connect workflows, stakeholders and partners in a seamless way

- Executes applications on remote resources.
- Enables widely distributed locations to collaborate on problems – either technical or business – asynchronously or in real-time.
- Manages and better uses spare compute cycles for low-priority applications.
- Allows sensors and instruments to be incorporated into grid computing environments.

GRID provides a distributed processing capability where large tasks are segmented and re-assembled as people come to share access to processing power itself. Linked with an 'on demand' business model it also allows users to throttle their monthly costs based on their own demand as they are charged based on their actual usage.

In the upstream environment GRID can deliver a uniform computing environment that helps optimise IT assets for all sites currently performing geoscience, engineering, technical and traditional back office business computing.

New business models

Perhaps one of the most exciting new developments is the concept of e-business on Demand™ or the provision of the delivery of standardised processes, applications and infrastructure over the network, as a service, with both business and IT. At present two solution areas are being offered:

- Infrastructure on demand, which includes content distribution, managed hosting, managed storage, network management and performance management.
- Business processes on demand, which includes, business exchange services, business intelligence, CRM management, e-commerce, e-learn-ing, e-procurement and e-workplaces.

Many of these models address the challenge of 'putting IT altogether'.

For more information on this, visit **www-3.ibm.com/e-business/doc/content/feature/vision.html**

The final word

Getting back to the theme of this article – has the upstream industry been unleashed by technology? If we include both IT and oilfield technologies then the answer is most definitely 'Yes'. In the view of the author this will continue to be the case with IT technologies offering a way to really transform the industry and help meet the challenges of production growth, the big crew change and the consequent need to institutionalise and share knowledge. In fact, aligning IT and data management strategies with business needs is even more critical than before. ●

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**The views expressed in this article are those of the author and do not necessarily reflect those of the IBM Corporation.*

Moving closer towards the digital oil company

The oil industry has been chasing ever-shrinking margin improvements for over 20 years. The next level of performance improvement will be far more challenging with better supply chain integration, control and asset lifecycle management from the wellhead, downstream through the refineries to the petrol pump, chemical and industry end-users. Some call it the digital oil company. *Brian Davis* reports.

The key for achieving this holistic vision is IT, the Internet in particular. But it is not just a matter of deploying new technology – the big challenge will be people and change management. As we have seen from the recent dot.com debacle, even the low hanging fruit like e-procurement has proved difficult and many multi-million dollar e-marketplace initiatives now languish or have disappeared.

The market is marked by consolidation, both in terms of oil industry players and the IT solution providers. Most companies are taking careful stock before the next leap forward. The recent AspenWorld 2002 conference in Washington DC was an excellent forum for putting the picture in perspective, in concert with other *Petroleum Review* contacts.

Leading process control software supplier Aspentech itself is facing difficult times, despite customers including BP, ChevronTexaco and ExxonMobil. The share price has plummeted in recent months and new CEO Dennis McQuillin has implemented a major downsizing programme. Despite current problems he is bullish about integration and future opportunities.

New acronym for collaboration

McQuillin suggests there are still $300–$500mn/y savings potential in the $6.5tn petroleum and chemical process industries. In the downstream oil sector, he sees potential supply chain efficiency savings of at least 50 cents per barrel. He claims the answer lies in Enterprise Operations Management (EOM). EOM calls for integration of distributed control systems (DCS) that automate plants with back office enterprise resource planning (ERP) as well as optimised management processes throughout the supply chain.

The petroleum and other process industries face growing complexity in silos of activity across the supply chain. Aspentech recently teamed up with Accenture to develop solutions for enterprise-wide applications. Data connectivity and data warehousing are vital components. These will commonly be accessed by role-based portal platforms (like the Aspen Enterprise Portal) to handle process workflows and performance management.

McQuillin claims: 'The foundational elements are largely in place for modelling, simulation, optimisation and control. The catalyst is the Internet, which will span management, engineering and the supply chain.'

The all-singing, all-dancing portal will be the lynchpin of any integrated digital enterprise. But there is considerable competition from vendors like SAP, IBM, Oracle and Microsoft, as well as DCS suppliers Invensys, ABB and others. Unfortunately there is no single solution so it is a field day for consultants and system integrators.

Analysts identify key challenges

Industry analysts like Bill Miller, Energy Partner at Accenture, stress that transforming the petroleum value chain must be 'business process driven not IT driven'. He recognises that net margins have been cut to the bone in recent years. Optimisation programmes date back to the introduction of DCS in the 1980s, ERP in the 1990s, and to the massive consolidation of 17 majors since 1997 to six supermajors – BP, ChevronTexaco, ExxonMobil, ConocoPhilips, TotalFinaElf and Valero.

Miller suggests: 'The next step will be far more difficult as we have to optimise the supply chain. While market volatility will continue to be a challenge. The introduction of ERP and e-procurement initiatives was just "training camp". The real game begins with EOM, which demands supply chain operations management excellence.'

Miller identifies four main components for supply chain optimisation:

- production optimisation,
- e-sourcing,
- product placing, and
- operational excellence using performance feedback tools.

Together these promise potential benefits of $0.35–$0.75/b recurring and a one-time benefit of $0.25–$0.5/b. Achieving this goal will be more of an art than science – reliant on culture change as well as new technology. 'KPIs need to be carefully defined from top to bottom in the corporate culture. And it requires a degree of collaboration that is almost unheard of in the oil industry,' remarks Miller.

Gartner analyst Karen Peterson agrees that by some definitions 'collaboration means working with the enemy!' She reckons this probably accounts for the failure of some public marketplaces. 'It does not mean squeezing the suppliers,' says AMR Research analyst Bruce Richardson. 'Information visibility is a key component, but that is proving difficult even within global organisations wishing to share best practice, let alone opening doors to key trading partners.'

Companies need to build an 'Adaptive Supply Chain', explains Forrester Research analyst Navi Radjou. The new system must be event driven, using web services to track performance; with real-time visibility, using sensors and technology like Radio Frequency ID (RFID) tags to connect

physical assets into a digital supply chain; and be self regulating with automated bottom-up control.

Andy Chatha of ARC Consulting suggests development of a collaborative culture requires greater focus on the customer, system synchronisation and performance optimisation. 'Make OpX (operational excellence) a top priority, using techniques like Six Sigma,' he states.

Promising portals

Generally, portals and exchanges like Elemica and Trade-Ranger help people to collaborate, as portals encourage better synchronisation of trading partners. Even smaller companies are getting the message. Recently the UK DTI and LOGIC announced the first project in their e-Collaboration Champion programme. Under the CIS Alliance, six companies ranging from CIS (the oilfield procurement arm of The Craig Group), Wellhead Electrical, FIS Chemicals, Henry Gibson Stationers, Gibb Tools and K&L Ross have teamed up to produce an online catalogue for e-procurement purposes.

CIS MD David Allan anticipates that 'the online catalogue will not only streamline our supply chain locally but will enable us to take that streamlined version to the global marketplace'. It is a strong ambition for the small, mostly Aberdeen-based suppliers. Earlier initiatives like OFS Portal, which was set up by major E&P contractors like Schlumberger, Halliburton and Baker Hughes, are still struggling to aggregate supplier content. Trade-Ranger is undergoing yet another revamp, and the Petrocosm e-marketplace is defunct.

'After all the e-business hype, there is now a sense of realism,' says LOGIC Chief Executive Chris Freeman. 'But collaboration is key with common access to data across the web.' LOGIC has a number of web-based initiatives underway, including a new website that will provide access to UKCS offshore plant and pipeline infrastructure data, and will initially carry data from BP, Shell and Amerada Hess.

Reverse auctions and e-sourcing were also hailed as great white hopes by dot.coms and software vendors. FreeMarkets, a leading global provider of e-sourcing software and services, reports that companies like BP, Shell and Marathon Oil have saved millions of dollars by e-sourcing direct and indirect goods and services.

But not everybody is happy. Members of the International Association of Drilling Contractors (IADC) are concerned their services are too complex for e-auctions. Many contractors are not prepared to stand up to fight in case they alienate the majors. 'But LOGIC couldn't get any contractors to give a positive image of their e-auction experiences,' says Chris Freeman.

On a more encouraging note, the Common Data Access (CDA) initiative set up by a 100%-owned subsidiary of UKOOA is being expanded. The CDA will offer a web-based repository of subsurface engineering data. The LIFT initiative has also been expanded by IndigoPool.com to cover fallow fields in the North Sea, with 50 blocks announced by the DTI in September 2002. LIFT will bring the web-based People On Board (POB) system online this month, to help 14 operators track personnel movements onshore and offshore.

Chris Miller, Shell International's Group Adviser on Strategic Sourcing, maintains that e-procurement accounts for 3–5% of the group's $22bn share of spend on goods and services worldwide. Shell businesses are already planning to raise this to 60% within two years. It will be interesting to see if this can be achieved given the earlier promise by BP's Sir John Browne to secure 95% of cataloguable items via the Internet within a two-year period – four years ago, and still a long way off.

New name, new focus

Readers of previous *Petroleum Review* IT and e-business reviews may be asking 'What has become of Trade-Ranger – the 'Lone Ranger' of e-marketplaces?' Since the departure of CEO Claire Farley, Trade-Ranger has yet to name a new CEO. Honor Guiney, Acting Chief Operating Officer says: 'We are rethinking the strategy and will obtain volume by driving value. The complexity of transactions in this business was underestimated.'

The exchange, now renamed TRX, is developing a range of offerings, with new tools above and beyond those provided by companies such as Commerce One. 'We are now focused on providing processes for end-to-end integration. At present major buyers are integrated into Trade-Ranger but not enough suppliers. The exchange will target integration on both sides, and analytics around spend and process improvement, for increased velocity, reduced transaction errors and major cost reduction.'

TRX currently has 20 buyers and 1,300 suppliers. One of the key founders, BP has chosen to use an alternative trading platform, although retaining an equity share in the exchange. But Shell and other partners maintain faith in the marketplace during this difficult transition period. The exchange anticipates reaching liquidity for buying members by 2004.

Guiney explains that the current marketplaces only address 25% of the total cost of ownership in the oil business. 'Although 25% of the cost may lie in the product, 75% lies in the process. We reckon we can help drive 20% of costs from the total cost of ownership, by automating the total lifecycle.' The aim is to drive large volume suppliers towards two-sided integration. A consultancy service will be offered to help small suppliers lacking an XML-engine, so online transactions can be integrated with back office systems.

TRX is also developing a 'transaction thumbprint', so several different technical and business rules can be captured around any transaction. The exchange is also creating a 'digital process model' that will remove 80% of the work necessary to link a buyer to a supplier. The exchange is also working closely with industry bodies CIDX, PIDX and XBCL to develop common translation standards for buyers and suppliers. A new Application Framework will enable users to handle travel, e-invoicing, RFx, auctions and other transactions on a 'plug and play' basis.

Chevron takes a different route

ChevronTexaco is going down a different route after the Petrocosm debacle. David Clementz, Enterprise Chief Information Officer, heads up a team that manages IT and e-business infrastructure across the globe in a decentralised, collaborative environment.

Typical industry spend on IT is 2–3% of that revenue. But Clementz estimates ChevronTexaco is spending considerably less 'as we've been able to drive standards across the organisation with greater productivity. Admittedly, the collapse of Petrocosm was a disappointment, but we've harvested the technology and understanding of the business model about how to get suppliers onboard. And we've built our own e-procurement initiative internally.'

The group now has 40 externally facing websites conducting business from transactions through to analysis – so retail jobbers in US convenience stores, for example, can check the status of fuel orders and accounts via the web.

A number of extranets handle upstream business with customers and suppliers. The Thailand business unit, which is sinking a new well every nine days, is connected to government partners TAIPO, partners in Houston and ChevronTexaco's corporate headquarters in San Francisco via a self-service hub. There are over 40 similar sites handling masses of data between internal parties and partners.

Clementz considers that the key to future success will be collaboration.

'ChevronTexaco has a very robust set of applications upstream, from visualisation to asset lifecycle tools. We're moving towards working as global virtual team, which can operate on projects round the clock.' By the middle of 2003 there will be a complete desk-ready infrastructure, featuring a 50,000 node network that spans 180 countries.

He suggests there are three major IT-driven goals. First, the need for cost reduction – using a common platform from the desktop to portals. Secondly, targeted productivity and efficiency gains. 'We've seen 50% growth in network traffic as the global core built up, which is a mark of productivity,' he says. Thirdly, enabling new business opportunities, such as high speed connectivity, that will offer a whole new way of working with customers in ChevronTexaco's retail outlets.

ChevronTexaco has been involved in 'The Oilfield of the Future' project for five years. It is outfitting wells with downhole sensors and remote infrastructure so performance can tie in to a database. The steam injection process at the Kern River field in Bakersfield is monitored using temperature sensors to minimise the heat required to generate steam. 'Sometimes the gas and steam are worth more than the crude,' says Clementz.

'There are opportunities to knit together functions upstream and downstream. We're moving towards full business simulation, making real-time decisions based on market decisions. Nobody has fully automated the supply chain. But platform to refinery connectivity is on the horizon within several years, subject to a robust, secure digital infrastructure. Pockets of collaboration will emerge in a few years.'

Downstream arena

Examining the issues around collaboration in the downstream arena, Accenture partner Parrish Potts comments: 'The big question in the oil industry is always around cost. Everybody is trying to drive out supply chain cost, reducing transportation costs, inventory costs and energy consumption while optimising plants. Some of the tools are readily available, but there's still a lot in development.'

Technology is not a barrier, but development of the integrated digital supply chain is likely to be evolutionary rather than revolutionary. 'The key drivers will be gross margin improvement. This demands yield improvement and optimisation of the product slate. And reducing raw materials costs by improved sourcing, better purchasing and evaluation.'

Potts recognises the value is not in reducing the cost of the transaction (where a lot of e-procurement was focused), but in the execution of the transaction. Buying crude and raw materials at the right price, from the right location and at the right time. 'Most refineries can achieve this mix occasionally, but tools for process improvement will help them achieve the goal more regularly. The aim is to reduce "give away and value leakage" in crude selection and supply management decisions,' he says.

At present there are significant gaps in data visibility. 'Culture is a huge obstacle,' comments Potts. 'Security is also an issue in the collaborative environment. But most of the new capabilities will be built around optimising the internal capabilities of an organisation. There is no "holy grail" or single vendor solution. This strategy is going to require integrating a large number of applications – from ERP to SCM, CRM and process control.'

Right now, most companies have some initiative in place. The challenge is to establish an end-state vision, and then put the necessary parts in place. Today, the danger is of having many uncoordinated but related initiatives, which can burn a lot of money but never get to the end-state desired. 'Few oil companies have really considered the full implications of the supply chain. They focused on the movement of barrels and not the gross margin improvement,' says Potts.

The digital oil company is a big vision – but is this what the business is evolving towards?


André Van Aken, speaking at i2 Planet, Prague

Supply chain management – meeting of minds

Much has been written about problems with the industry supply chain – not least within the pages of this magazine. A viable supply chain management (SCM) solution is still the Everest the industry has to climb. However, two companies look as if they could be nearing the summit, Shell Global Solutions (Shell GS) and value chain provider, i2 Technologies have joined forces and expertise to develop, what they hope will become, the industry-standard SCM solution. *Emma Parsons* meets up with both companies to discuss their latest developments at i2's executive Planet forum in Prague.

The initial announcement regarding the partnership was made in May this year, by Greg Lewin, Vice President – Manufacturing, Supply and Distribution – Shell Oil Products, at Planet i2, Las Vegas.

He stated that the objective of the initiative is to restructure and revolutionise the way the downstream value chain operates. Optimising business practice within the supply chain unleashes the potential to create extra revenue and create savings in the region of $35mn/d globally, he claimed.

Analysts such as Ernst & Young and Cap Gemini have estimated that savings can be made by squeezing 50 cents out of every barrel of oil sold.

So how do they plan to achieve this? Their answer to that is by restructuring and transposing the way the supply chain has been historically applied – from being supply driven to becoming demand driven – and by applying across the board 'live' integration. Ultimately the right-hand will effectively see what decisions the left-hand has made and act accordingly.

The 'chain' gang

One question to be asked is why a partnership, rather than a client/supplier relationship?

Jeremy Bentham, Vice President, Shell GS explains: 'we have been seeking to combine our domain expertise and knowledge of the oil and petrochemicals industry, and our application knowledge with an innovative hi-tech provider of applications in the supply chain. We went through a rigorous process of assessing who were the potential partners to bring those two skills together. i2 is our selected partner for building that knowledge platform.

Basically it's a very complex path that we're on in which there are lots of benefits on both sides and to bring that together in the partnership mode we believe to be a more effective way of achieving some of our aims. So from Shell's point of view, there's effectiveness in terms of efficiency and in terms of costs in developing the solution.'

André Van Aken, APS Programme Director, Supply Chain Integration Initiative, Shell Oil Products (right) explains 'if you want to look at the market-place today there is not a solution we could buy 'off the shelf' in a supplier/customer relationship. We are also deeply aware that Shell is not in the software business – just working with Shell would present us with a number of different problems in making sure the solution stays the best in the world'.

Amir Kazmi, i2 Vice President, Global Energy and Chemicals Business Unit, adds 'from an i2 point of view the attraction for us was Shell's domain knowledge – 44 refineries, massive global presence, brand recognition – Shell GS not only offers these services within Shell but also to other oil and gas companies. This allows us to penetrate the market more widely. Combining all this together it's a good partnership'.

Analysis of the 'chain'

According to Van Aken the oil industry has been the first to apply mathematical techniques to select which crude to buy and process in its refineries since the early Sixties. Traditionally, the linear programming technique has been very successful. However he explains, 'if you look what has happened over the last decade, the manufacturing industry has shown enormous advantages – especially the electronics industry – in applying integrated supply chains over a total range which far outweigh the amount of integration that we have established in our industry. To a large extent, the complexity of producing oil in a refinery gives rise to rather complicated physical/chemical models, therefore the problem of solving integration is not so easy. If you look at our strategy a number of years ago, we found that in order to address the customer problem we do have to tie things together more. If you want to solve the total problem, it is more efficient to start from the integration problem and later supplement the required simulation – the physical/chemical specifics of the simulation and the mathematical optimiser

on top of it rather than the reverse'.

Bentham is in an ideal position to understand and address the issues faced by the oil and gas industry in supply chain management. Formerly the Refinery, Supply, Economics Scheduling Manager in Shell Nederlands where the company has one of its biggest refineries, he has hands-on experience in developing many of the business processes and knowledge which now compliment the current integration of the application.

He says there are a 'very complex set of activities – hundreds of crudes ultimately ending up with thousands of products. It goes all the way from crude trading to distribution and transport of the products as well as receiving massive refining and petrochemical activities into the terminals.

The question is how does the industry deal with something as complex as that? Historically it has tried to simplify it as much as possible by handling it in chunks – those chunks often end up in different organisational units. By fixing as much as can be fixed for the foreseeable future then other people can go and make their decisions in the chain. In the face of developing events the industry reacts on the whole by trying to remain feasible with as much fixed as possible, and hence all kinds of inefficiencies are introduced and opportunities missed. The industry is naturally volatile – whether that's price volatility or whether it's disruption to distribution due to floods – and this can have a huge difference on your operations and business performance.

Instead of this process what we are aiming to say is: "we are going to tie the supply chain together in a way so that the decision makers are tied together – therefore business processes and business knowledge are critical."

So instead of breaking up these chunks we are addressing the complexities by having a single set of information available – and a single set of applications coupled with the business processes involved'.

The solution

i2 have an interesting perspective on the management of supply chains in multiple industries having invested over $2bn in developing SCM solutions. This helps development in terms of the company having an underlying technology platform that can be adapted to suit the requirements of the oil and gas industry. This is basically what they are doing – expanding the existing technologies platform to address the requirements. 'It does give us a unique perspective to work with Shell and one of the benefits of a partnership is that we can explain and examine lessons learnt – even though they are not directly applicable – but lessons learnt in other industries. And both sides are learning. The greatest success learnt today – we've learnt and we've gelled as one team in terms of how we're moving forward in this partnership' says Kazmi.

The most dramatic example of how these systems can benefit the user company are illustrated by Van Aken, 'if you assume a major event, for example, a production unit shuts down unexpectedly. The only consequence isn't that we don't get the production from that unit – but that we do have to go quickly into the markets to make sure our customer base is covered. The speed of response can now be cut down from a day or two days to a matter of hours. This is of extreme economic importance to us and to our customers'.

Bentham adds, 'the integrated system would enable the industry to be as effective as possible in responding to developments. For a company using this solution there are probably five areas where they would see the benefits. These are namely:

- transportation and terminal management;
- marketing/sales channels;
- product/supply economics – which feature the pricing and make, buy, exchange decisions. Also by being able to respond to those events caused by ongoing changes in demand you stop distressed movements – you prevent all kinds of duplication and rework;
- better management of information-on-demand;
- introducing more economic drivers into the complex scheduling processes'.

They all come from flowing through information from the demand side all the way through the process for all the decision-makers – and that's why you need to have this integrated approach – so the decision-makers have access to the same sets of tools that everyone else is working with.

The attributes mentioned are that it will be one solution that will work with many geographies – it can fit the US as well as the Asia-Pacific markets – catering for the various local requirements and is a fully integrated solution in that it covers not only planning at a strategic level, but operational planning – and then refinery optimisation and execution. One will get the complete handshake on integration.

Rollout and testing

The product is to be released in a number of modules. The first module is in the process of being tested by Shell. It will take the next 14-18 months for the development of the whole solution to be completed. The first to be released will be the demand-management module. Following testing of this module, the next roll-out will be for transportation manager which focuses on the primary distribution and logistics part. This is due to come out sometime in 2Q next year.

Following these the overall supply chain planning and refinery scheduling are slated for the end of next year.

A specific training programme for the modules is currently being devised. As Kazmi says, 'our SCM strategy is that we recognise – and this is part of the partnership– that i2 cannot do this all by themselves and neither can Shell GS, so we are talking to other consulting partners and we will work with other partners. We will put in the core programmes between i2 and Shell GS – this would consist of using our relevant areas of expertise – but there is a whole host of other areas and services that are required to employ the solution that together we don't have the expertise for. We will also buy in resources from the rest of i2 organisation as we need them or from our external partners'.

Shell Global Solutions and i2 Technologies – the companies

Shell Global Solutions is a close network of independent companies in the Royal Dutch/Shell Group of companies. It is a commercial provider of solutions supporting operational strategy and business performance improvement in the industry.

Shell GS provides professional services to companies within the Shell Group and joint ventures as well as to non-Shell businesses. The company employs in the region of 2,750 people world wide. For the past three years, it has been concentrating on enhancing the efficiency and effectiveness of operations within the industry.

i2 is the leading provider of value chain management solutions. i2's value chain management solutions help companies plan and execute the activities involved in managing the supply and demand. These solutions span the entire scope of value chain interactions, including supplier relationship management, supply chain management and demand chain management. Visit **www.i2.com** for more details.

As Bentham, states, 'it's not just buying a licensed piece of software, there is a whole process to go through to ultimately realise the full value with the way our future customers do business/take decisions that are all facilitated by these applications. This is why people with domain knowledge like Shell GS are an absolutely essential part of taking people on that process.

The investment from both companies is illustrated in terms of head count.

Shell GS has about 60-70 people as well as others developing the underlying infrastructure within Shell, while i2 are employing in the region of 100 people who are 90% dedicated to the project. All in all about 200 total, however the companies maintain that successful roll-out in Shell will require a significantly increased number.

Future developments

The present solution has been designed for the downstream arena, however the companies are looking at specific requirements to tailor the solution to the upstream sector. Ultimately they say they are looking at more of an asset-life cycle system solution for the upstream side of the business and this will logically extend into Chemicals and eventually into Retail.

Shell GS maintains that there has been a huge amount of interest from the rest of the industry as well as through their client list.

Kazmi adds, 'we've seen from both sides a tremendous amount of interest and the interest has sort of qualified for us, this is a generic industry problem and there is a generic industry opportunity here and everybody's interested in getting the value out of solving this problem. And that's not only been validated by other oil and gas companies but all the management consultancies, the strategy consultancies that we've talked to, have all said that this is the right way to go'. ●

Developing the best and the brightest

Martin Tims (right), Manager of Education and Environment Programmes for ExxonMobil in the UK, joined what was then Esso in 1968 having gained a degree in Chemical Engineering and Fuel Technology at Sheffield University. Since then he has held 10 different positions with the company, across the spectrum, culminating in his present position from which he is soon to retire. Recently interviewed by _Petroleum Review_, he stressed how vital it is for oil and gas companies to work in partnership with the education sector in order to secure the industry recruits of the future.

Q. How has industry's relationship with the education sector evolved over the years?

A. The easiest way to illustrate this is with a diagram that starts off pre-1986 with the education world and the industry sector as two separate entities (a) working in their own 'secret gardens', far apart. There was then the horrendous situation with the two at loggerheads – what I call the 'apartheid period' (b), where the education world thought industry was a 'dirty word' while industry thought the education sector was letting it down by not producing the right sort of recruits. That then spawned 'Industry Year' in 1986, the idea being that we could at least start talking to one another – the 'dialogue' part of the diagram (c).

The two sectors soon realised that they had quite a lot in common and a partnership resulted (d). The Teacher Placement Service (TPS) started up as part of this process, whereby teachers were given the opportunity to come into industry for a few weeks at a time while industry placed secondees into colleges and schools.

The future is of growing 'integration' (e), where the two worlds overlap. For example, we now have students at Key Stage 4 who, within their curriculum, spend part of their time in industry. We also encourage our people into 'Link Schools', where they can help deliver lessons. At the end of the day we are trying to achieve the same thing – improving the skill level of 'UK plc'.

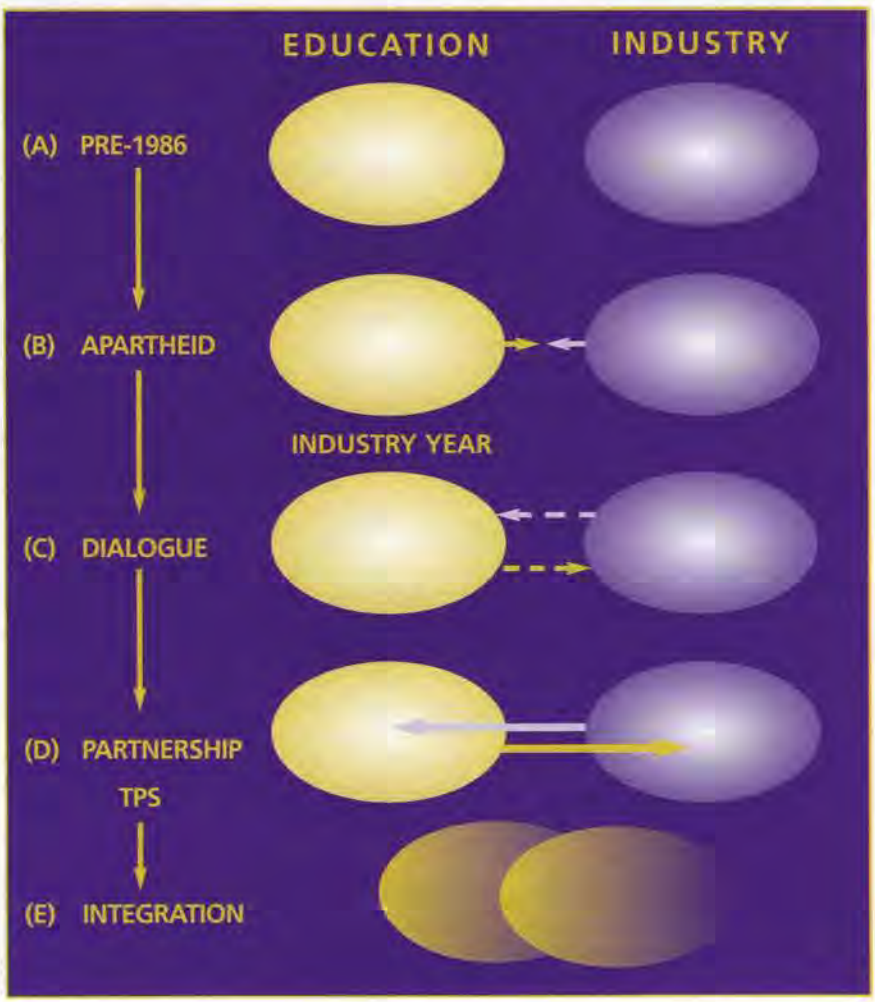
The Institute of Petroleum's Education Department is playing an important facilitation role in this move to integration. It can operate on a pan-industry basis, taking the enthusiasm, good will and funding that are available on both sides and putting them to their best effect.

There are many ways the integration can take place, and many good schemes and projects. Some people, however, think there are too many, and there has been a tendancy in the past to try to get a 'one size fits all ' approach to industry working with education. What we actually need is better marketing of the *range* of schemes that are available. So many schools still don't know what industry can offer and, equally, many SMEs don't know what schools want or need.

Q. What do you see as the real education challenges to the industry?

A. From the industry's point of view I guess it is managing and controlling the expectations of the schools and colleges. We have a business to run and have a bottom line to meet – while we would like to help all of the time with all of our people, all we can do in reality is put discrete amounts of money and human resources to help – and make sure this is done in a cost-effective manner.

What I also find is that very often the schools need educating on how to approach industry for help. When I first started, it was very much a 'begging bowl' approach. However, what we have done over the past 10 or 15 years is to say to schools that the only way that this is going to work is as a genuine partnership, where both sides benefit



from working together. While it is fairly obvious to the schools what they get out of working with industry, it is often less clear to them what they can offer in return – yet there is a wide range of benefits that they can bring to such a partnership. These can be divided into three categories:

Human resources – For example, if we put some of our younger managers into schools they can develop management skills by working with the students. Both sides can also develop interview techniques when our link schools want to give their sixth-form students interview practice prior to the employment milk rounds. Then there is the increased morale of our staff by seeing their company working with their children in the link schools.

Public Relations – Schools can provide a lot of help here. For example, if a company has changed its name recently and needs to establish a persona in the community, what better way than to work with the local community schools? Good mentions in the press benefit individuals involved, companies and schools.

Services – Very often small local companies need help with marketing; schools can help with survey work, or offer their language expertise. Schools also have a lot of physical facilities to offer – such as the use of a swimming pool or squash courts after school hours for a negotiated fee. The same goes for car parking, catering, meeting rooms, etc.

Q. How important are formal qualifications and which qualifications does the industry regard as key?

A. Formal qualifications are just one of about five areas that we would look at when taking on new employees.

They must have the basic 'three Rs' to a level of 'unconscious competence'.

They need appropriate high level knowledge – not only the subject knowledge, but also the ability to use it.

A whole raft of 'core skills' is required, including general literacy and communication skills (a foreign language is often an advantage), IT literacy and teamwork skills.

The ability to update one's personal skill set is also increasingly important in today's technological world – what is often called lifetime learning or continuous professional development.

Motivation and attitude – the importance of this last area is often not recognised, but it is just as important as qualifications. After all, we all work best when we are motivated about what we are doing.

The focus of attention on these five areas has changed over the years.

Recruitment was originally very much formal qualification-based, with maybe as much as 90% of recruits having 'specialist' qualifications, such as an engineering degree, that were directly related to the job. Today, however, a whole different skills set – including creativity, teamwork, presentation skills – is required... qualifications are no longer the be all, and end all. Today, perhaps just 40% to 50% of recruits have specialist qualifications, the remainder offering more 'generalist' skills.

Q. What do you see as the key attractions of the industry to new entrants?

A. The oil and gas sector is an exciting industry and still has a long way to go. A lot of people ask 'What will happen when oil runs out?' – our response is that it won't run out, but it will go much further if people use it properly. Fuel efficiency is becoming increasingly important, as are the development of approaches such as enhanced oil recovery and the use of fuel cell technology. The industry has one hell of a future – there are a lot of rewarding careers on offer, with the opportunity for travel for those who want it.

Q. If you could offer one piece of advice to industry, what would it be?

A. Work with schools at all levels – because if we don't catch the children at a very young age, and work with their teachers, then we aren't going to get the best and the brightest recruits coming into the industry. It can be hard to justify this when times are hard and when you have lots of other jobs sitting on your desk. But I do believe that people have to put some priority behind this... at the end of the day, if we don't get the best and the brightest, our industry won't survive.

Q. If you could offer one piece of advice to prospective new recruits, what would it be?

A. Keep your options open, and keep learning. Please. Come into a company like ours or any of the other majors and you will get a very rewarding career, with job satisfaction, a good salary and good benefits package. But recognise that it is the brightest and best that are being promoted, and this can often mean moving around inside companies, moving careers or even moving your whole way of working.

Q. What does the future hold for you, and what does it hold for the industry you are leaving behind?

A. The second part to your question is more easy to answer as whatever happens the world will need energy in some shape or form. However, fossil fuels are a finite resource whether we like it or not so we will have to use fossil fuels more efficiently, but also new sources of energy will have to be developed.

However, there has been a lot of investment over the years in petrol stations, internal combustion engines and diesel developments and we can't, no matter what some activist green organisations say, just suddenly throw it all out overnight and go back to the horse and cart! Renewables do have a place in the equation but, equally, there is a need for much more research on better and better ways to utilise fossil fuels in even more environmentally friendly, and more efficient and economic, ways.

As far as my future is concerned, I intend to spend the first three months or so reflecting on where I've got to and where I'm going. I certainly don't want to go from what I am doing in the paid sector to doing it all on a voluntary basis! That said, I will retain an element of connection with the education sector as I am Governor of a big local primary school and am probably soon to become Chairman of the Governors. There is also talk of whether I could put together a lecture series on how education and industry can better work together, identifying and sharing benefits. Both industry and the education sector need to work more on quantifying what the benefits are of working together. We are all too good at identifying the financial *cost*, but until the *benefits* of working together can be quantified, it will be impossible to work out the true cost benefit analysis, and hence to take the longer-term approach that is needed.

But what I really want to do is take up all those social and leisure activities that have been sacrificed as part of having a full-time career. I also plan to develop new interests – I am soon due to go to the first of series of lectures in archaeology and may well end up going on digs up and down the country. Then again, I might get back into amateur dramatics and/or become a film extra!

Can Caspian oil challenge Middle East supremacy?

A lot has been written about the oil potential of the Caspian Sea. Some sources have described it as the 'great prize' while others talk of it as if it were a new Kuwait. Fanciful estimates have even claimed that Caspian Sea oil reserves rival those of the Middle East. Others have ascribed potential recoverable reserves of 200bn barrels to the area.[1] The Caspian Basin has been over-promoted by some as a new Middle East, and as an alternative global supplier to the Gulf. Others, in contrast, see it as an overstated high-risk oil province that will remain, to a great extent, isolated from world markets. The reality, as always, is somewhere in between, writes *Dr Mamdouh G Salameh.

The Caspian Sea's proven reserves are at present estimated at 16.8bn barrels, or 1.5% of the world's total proven reserves.[2] However, there is now some confidence in the view that the proven oil reserves of the Caspian fall within the range of 18–20bn barrels, with a yet-to-find (YTF) recoverable oil reserve of around 50bn barrels. The bulk of these reserves lie within the North Caspian Basin. Drilling failures in the South Caspian Basin and a comprehensive geological appraisal suggest that there is little further prospect of new oil, even in the untested deep-water traps of the South Caspian that are currently subject to territorial dispute. By 2010 the Caspian should be producing some 3mn b/d. However, this depends on a timely investment in new Caspian support infrastructure and large-scale project financing.[3]

Apart from the limited size of the reserves, Caspian oil is very costly to find, develop, produce, and transport to world markets. The Caspian Sea is practically a landlocked area, and the economic and geopolitical problems arising from transporting the oil by pipelines through other countries add to the risks of investments there.[4]

With these apparent disadvantages of the Caspian Sea oil in mind, a puzzling question arises – why the rush of so many American and international oil companies to invest in this region? Under normal market conditions, investors would naturally turn to the abundant, low-cost oil of the Gulf, rather than to these high-cost, politically hazardous areas.

Why invest in the Caspian Sea?

With the demise of the former Soviet Union (FSU), the Caspian Sea presented western oil companies with a unique opportunity to acquire potentially huge oil reserves at low technical risk. These companies were fully aware that these reserves were located in a region where both political and business risks were exceptionally high. The newly independent Caspian republics saw western oil investment as a safeguard for their newly won independence from Russia.

The Caspian Basin has a long history of oil and gas development. Western technology has confirmed most of the ex-Soviet Caspian oil and gas findings. Consequently what drove the original western energy investment in the Caspian was access to three proven but undeveloped ex-Soviet super giant oilfields – Tengiz and Karachagenak in Kazakhstan, and Azeri-Chirag-Guneshli in Azerbaijan. These three fields still dominate the Caspian energy scene today, with the addition of two new super giant oil and gas discoveries at Kashagan in Kazakhstan and Shakh Deniz in Azerbaijan.

The declared US policy has been to encourage investment in the Caspian and to establish US interests in the geopolitically sensitive area situated near both Iran and Russia. It is also a declared policy of the US to develop Caspian Sea oil in order to reduce dependence on oil from the Gulf, which is viewed as an unstable region where political upheavals or wars could again interrupt oil supplies and cause price shocks.[5]

For the US, the support of Caspian oil development began as an outgrowth of a national energy policy that calls for the expansion of oil production in areas outside the Middle East.[6] The US policy subsequently evolved over time to one that came to embrace three main policy goals in the region:

- Support for the sovereignty and independence of the Caspian newly-independent states (NIS). The US takes the view that oil is the key to the economic viability of these countries.[7]
- Enhancing commercial opportunities for the US and US companies.
- Building economic linkages (such as pipelines) between these states as a way of benefiting countries of the region and reducing conflicts.

In pursuing these objectives, the US has supported the establishment of an east–west energy transit corridor that comprises a network of multiple pipelines that will bring Caspian oil to world markets while bypassing the potential choke-point of Iran and also reducing dependence on Russian oil pipelines (see **Table 3**).

Caspian Sea oil reserves

The proven oil reserves thar are in the Caspian region (Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan) amount to 16.8bn barrels (see **Table 1**). Estimates of 40–60bn barrels as the ultimate reserve base of the Caspian region are judged to be reasonable by most geologists familiar with the region. However, these estimates require drilling to take place, requiring huge investments and large rigs that have to be transported over excruciatingly difficult routes.[8]

Of the three distinct geological basins underlying the Caspian, the Northern Basin is geologically the most promising, followed by the Southern Basin and then the Middle Caspian. Estimates put proven oil reserves in the Northern Basin at 8–10bn barrels, while speculative recoverable reserves are seen to fall within the 40–50bn barrels range. Proven reserves in the South Caspian Basin are estimated at 7–8bn barrels, while those in the Middle Caspian Basin range from 4–5bn barrels.

From this reserve analysis one can safely predict that by 2010 the Caspian

Country	Proven reserves
Kazakhstan	8.0
Azerbaijan	7.0
Uzbekistan	0.6
Turkmenistan	0.5
Others	0.7
Total	**16.8**

Source: BP Statistical Review of World Energy, *June 2002.*

Table 1: Caspian Sea proven oil reserves (bn barrels)

	2000	2005	2010	2020
High case				
Production	1.35	2.45	3.89	6.18
Consumption	0.53	1.26	1.55	2.61
Net exports	0.66	1.19	2.34	3.57
Low case				
Production	1.35	1.93	2.77	4.84
Consumption	0.53	1.06	1.26	1.86
Net exports	0.66	0.87	1.51	2.98

Sources: IEA's Caspian Oil & Gas Study/BP Statistical Review of World Energy, *June 2002*

Table 2: Oil production, domestic consumption and net exports (in mn b/d)

should be producing 2–3mn b/d. Two-thirds of this oil will flow from the North Caspian and one-third from the South Caspian. Continued Caspian energy investment will still have to depend on three factors – first, a global price in excess of $20/b (in real terms); second, the absence of major political dislocations; and third, the need to upgrade with some urgency the Caspian energy support infrastructure. By 2020, production could potentially reach 5mn b/d, primarily from the North Caspian. This too will only happen if there is a significant improvement in both the business and political risk environment in the region.[9]

Production and export potential

In 2001, total Caspian oil production reached 1.47mn b/d, with net oil exports amounting to 755,000 b/d.[10] However, a 1998 International Energy Agency (IEA) study on Caspian oil and gas presented high and low scenarios for oil production, domestic consumption and the export potential of Kazakhstan, Azerbaijan,Turkmenistan and Uzbekistan over the period 2000–2020 (see **Table 2**).[11]

As a result of the commissioning of the CPC Tengiz-Novorossiysk pipeline in October 2001, oil pipeline export capacity has risen from 800,000 b/d to the current 1.4mn b/d (see **Table 3**). Capacity is projected to rise to 2.4mn b/d with the eventual completion of the BTC (Baku–Tbilisi–Ceyhan) pipeline in 2005.[12]

Multiple export routes with competitive tariffs are working well. Attractive netbacks and regional markets thirsty for oil will dictate a predominantly westward movement of Caspian oil to the Mediterranean and Black Sea markets. Within a 10-year timeframe, these markets will be expected to absorb 2.5–3.0mn b/d.[13]

However, the new CPC pipeline faces a number of difficulties. Turkey is uneasy about the increasing levels of traffic through its already congested Strait of Bosphorus that connects the Black Sea with the Mediterranean and may apply restrictions to the number of vessels using this route. The other major consideration is that use of the CPC pipeline still leaves Kazakhstan dependent on Russia. Total oil flows through the Bosphorus have grown significantly – but not massively – in recent years. Between 1998 and 2000 growth was 7% per year, reflecting both the commissioning of the Supsa terminal and the impact of high oil prices on increased Russian production.[14]

Another export route planned for Caspian oil is the 1,730-km Baku-Tbilisi-Ceyhan (BTC) pipeline. Construction started in 2002 and the pipeline is projected to transport 1mn b/d.

One problem associated with BTC is political instability in war-torn Georgia. Another problem is that oil production in Azerbaijan by itself is not sufficient to justify the high $4.2bn cost of the project. The pipeline is also not suitable for the other Caspian states as they lie to the east of the Caspian and, to supply to the BTC, an additional sub-sea pipeline would have to be laid across the Caspian. The territorial division of the Caspian is still unresolved with Iran and Russia, for political reasons, showing little interest in its resolution.[15] Indeed, the presidents of the five littoral states surrounding the Caspian Sea failed in a two-day meeting in Ashgabat in Turkmenistan in July this year to agree on how to divide the offshore oil and gas wealth of the Caspian. Iran has insisted on a 20% share, although its coastline entitles it to only 12%.[16] Russia has, however, recently reached agreement with Azerbaijan and Kazakhstan over the sectoral division in the North Caspian (see p40).

A southern outlet for the Caspian Basin's oil through Iran is the route most favoured by the international oil companies. It is by far the least costly option as there already exists an oil pipeline infrastructure in Iran. The 240-km Nekha-Tehran oil pipeline with a capacity of 175,000 b/d, which is expected to come online by 2003, would allow for oil swap operations.

Significant volumes will eventually move south to Iran (up to 500,000 b/d), for oil swaps from the Gulf. Caspian crude is sold to refineries in northern Iran for domestic markets and paid for by Iranian crude delivered at an export terminal in the Gulf for onward sale by Caspian producers in international markets. Both parties thereby benefit from from the saving of transportation costs across Iranian territory. Iran will, however, always be a market for Caspian oil primarily coming from Kazakhstan and Turkmenistan. But until the US softens its stance on Iran and lifts the sanctions, an Iran route will not be on the cards.

The CPC's eventual capacity of 1.6mn b/d and the projected BTC's capacity of 1mn b/d might not be able to handle all the 3–5mn b/d of Kazakhstan oil that is projected to come out of the Caspian in the next 15–20 years. There could be a need for three, may be four pipelines. In this case, Iran could be a possible third outlet for Caspian crude, despite the current US law prohibiting US companies from investing in the Iranian energy sector.[17]

Some commentators have suggested that a peaceful Afghanistan could host an oil pipeline from Turkmenistan to a port in Pakistan. However, most Turkmenistan oil reserves and prospects are 500 miles from the proposed pipeline and are closer to the various systems competing for Caspian oil exports.[18]

Caspian and world oil prices

The future of the Caspian Sea and its impact on Gulf oil will depend crucially on oil prices and on the investment policies of the major producers of the Gulf region itself. It is high prices artificially maintained by Opec that justified investing in high-cost Caspian Sea oil. Nominal fixed and variable costs per barrel in the Caspian Basin are on average four times those of the Gulf.[19]

Today a fully built-up cost for the Caspian barrel of oil is roughly $12–$15/b.[20] This compares well with the North Sea but is still some three to

Pipelines	Current capacity	Projected capacity
CPC (Tengiz-Novorossiysk)	600,000 b/d	1,600,000 b/d
BTC (Baku-Tbilisi-Ceyhan)	Planned	1,000,000 b/d
Baku-Novorossiysk	600,000 b/d	600,000 b/d
Baku-Supsa	200,000 b/d	200,000 b/d
Baku-Tabriz (Iran)	Proposed	250,000 b/d
Tengiz-Uzen-Kharg (Iran)	Proposed	500,000 b/d
Total capacity	**1,400,000 b/d**	**4,150,000 b/d**

Table 3: Current and projected Caspian oil pipeline capacity

four times more than the equivalent barrel in the Gulf. Future Caspian built-up costs should fall to within $10/b.

Caspian oil production targets of 3–4mn b/d by 2010 can be achieved only when oil prices exceed the $20/b level.

Impact on Opec

Incremental production from the Caspian Basin can at the margin contribute to a weakening of oil price levels. But it is unlikely to be a major threat to the market share and market power of the Gulf producers. Therefore, the Caspian Basin potential alone does not justify Gulf producers implementing production policies that would drive down the price of oil simply to discourage Caspian oil development. [21]

An exportable Caspian oil surplus of the order of 2–3mn b/d by 2010 could end up flowing towards the European market. It is quite plausible that these barrels will replace some Middle East barrels. This will occur just as Latin American production starts to meet a larger share of North America's growth in import demand. The result will be that Caspian and Latin American output will meet much of the growth in the Atlantic Basin's crude oil imports. This could redraw the crude trade patterns, pushing Gulf oil supplies increasingly away from the Atlantic Basin towards the Asia-Pacific region.

By 2010, the flow of oil from the Gulf to Asia is projected to rise by at least 6.5mn b/d but will fall by 100,000 b/d to North America with or without the Caspian oil. However, with Caspian oil, the flow of oil from the Gulf to Europe will fall by 1.5mn b/d compared to a rise of 500,000 b/d in the absence of Caspian oil.

It is estimated that without Caspian oil supplies, nominal oil prices in 2010 could be as much as $5/b higher than otherwise. But with Caspian oil, oil prices could be lower in 2010 by an estimated $2–$5/b.

Implications for energy security

During the Cold War, the primary threat to the flow of oil from the Gulf was Soviet control. A lot has changed since then. The Cold War is over and the perception that the FSU could control oil flows from the Gulf is gone. The focus has instead shifted to the potential of oil supply disruptions resulting from conflict in the Middle East.

Another development shaping the issue of energy security has been the proliferation of oil-producing countries. Between 1978 and 1996, 22 new non-Opec countries began producing oil, an increase of more than 40%. This is due, in part to the break-up of the FSU, but it also includes new producing countries in Africa and Asia.[22]

However, concern over energy security will never go away; but each new supplier contributes to the perception of a diminishing threat. In this case, the Caspian does enhance energy security by providing a volume of oil that is not unimportant as an alternative source.

Caspian development challenges

There are three most serious challenges to the development of Caspian Sea oil resources. The first is the transportation challenge complicated by high geopolitical stakes and widely divergent interests of the parties. The second is the slow progress in establishing reasonable 'rules of law' in each of the Caspian states. The third challenge is the unresolved issue of joint ownership and management of the Caspian undersea resources.

The Great Game

At its simplest level, the Great Game is about who owns the oil reserves of the Caspian Basin and who controls the pipelines that carry the oil to the global markets. While the new players differ in their perception of the game, the stakes involved, however, remain unchanged – power, influence, security and wealth.[23] Caspian oil could offer an important source, diversifying supply.[24] In consequence, as a powerful geo-strategic key, oil offers the region's states the best opportunity for true independence in 70 years.

Finally, with 40–60 bn barrels, the potential for national and commercial profit is substantial.

In a wider context, Caspian oil is tied to, and will affect, issues central to current and developing relations. These include the political and economic future of Russia and its behaviour towards neighbours and former Soviet republics; the political and economic future of Turkey; Iran's position in the region and its relations with the West, with Russia, and with its neighbours in the FSU; and the strategic consequences of greater dependence on Gulf oil.[25]

It is too early to declare the game over. But after years of inconclusive wrangling, the 21st century version of the Great Game is starting to yield clear national and corporate winners. Among companies, BP, Eni of Italy and (above all) ChevronTexaco of the US appear to hold claim to the bulk of regional reserves, as well as crucial pipeline routes. Among the countries, the clear winner is Kazakhstan, which is now believed to hold up to 75% of all Caspian reserves. With 10–17bn barrels of proven reserves, Kazakhstan is on the verge of becoming an important oil player.

The US can also celebrate a strategic victory – it is now close to achieving its goal of ending the old Russian monopoly on Caspian export pipelines. The centrepiece of US policy has been to promote the Baku-Tbilisi-Ceyhan pipeline. Despite lingering doubts about the safety of the war-torn route, financing and the size of Azerbaijan oil reserves, construction on the $3bn project is set to begin this year. Oil is slated to flow by early 2005.[26]

At the same time, President Putin of Russia appears to be plotting a Russian comeback. He has been travelling around the Caspian, laying the groundwork for a regional supply cartel, a kind of mini-Opec led from Moscow. It is not inconceivable that Putin will one day convince Russia's former satellites that together they can move markets to their own advantage.[27]

Iran is looking like a major loser in the Caspian, at least for the time being. Tehran insists the Caspian is a lake, which under marine law would give it a claim to 20% of the underlying oil fields. Azerbaijan counters that the Caspian is a sea, which would enlarge its own claim while cutting Iran's to under 12%.

In the final analysis, the actual winner of the Great Caspian Game is the one who is in the strongest negotiating position. The US and western oil companies seem to be in that lucky situation.

Conclusions

There is now a very clear technical and commercial understanding of the realistic oil potential of the Caspian Basin. In the

past six years Western technology has to a very large extent confirmed earlier Soviet oil and gas findings. By 2010 the Caspian should be exporting some 3mn b/d. Some of this oil will move south to the domestic markets of northern Iran (500,000 b/d); but the bulk will be transported westward to markets in the Mediterranean, where it will compete against comparable crude supplies from the Middle East and North and West Africa.

However, with ultimate reserves of 40–60bn barrels, the Caspian Basin does not pose a major challenge to the supremacy of the Gulf as a pivotal supplier of oil to world markets. Apart from the limited size of the reserves, Caspian oil is very costly to find, develop, produce and transport to world markets.

Incremental production from the Caspian Basin can at the margin contribute to a weakening of oil price levels. It is estimated that without Caspian oil supplies, nominal oil prices in 2010 could be as much as $5/b higher than otherwise. But with Caspian oil, oil prices could be lower in 2010 by an estimated $2-$5/b.

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WINNERS

Communication Award

- **Bob Tippee, Oil and Gas Journal**
  Oil and Gas Journal – The First 100 Years

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International Platinum Award

- **Chris Freeman, ConocoPhillips UK**
  Decommissioning of the Maureen Oil Platform. A Benchmark Project

Catch a wave

The recent contraction in the VLCC fleet has helped underpin a boom in freight rates

Photo: Bergesen

Beset by security worries as well as the usual safety and environmental concerns, not to mention rising fuel and insurance costs, 2002 has not been the best time to be a tanker owner reports *Petroleum Review*.

Had this annual review of developments in the tanker sector appeared in last month's issue of *Petroleum Review*, it would have presented a very different story. It would have told of a year in which the freight markets were fairly stable, tending to weaken, and would have concentrated on security concerns and increasing environmental regulation.

However, since the start of the fourth quarter the market has changed out of all recognition, particularly for the larger vessel sizes, with spot rates doubling in the space of a few weeks. The question that owners and charterers alike are asking is whether this is a short-lived phenomenon or whether the structural changes that have been taking place slowly in the industry over the last couple of years have fundamentally altered the nature of the market.

Where the boom started

The beginnings of the market upturn coincided with the terrorist attack on the very large crude carrier (VLCC) *Limburg* off the coast of Yemen on 6 October 2002. While this incident alone cannot be blamed for a doubling in spot rates for VLCC liftings in the Middle East, it does seem to have put into sharper focus background concerns over the security of supplies in the event of military action in the region. In this regard the market is behaving very much as it did in the run-up to the Gulf War in 1990, when any available tanker was pressed into service to get as much oil as possible out of the region, even if there was no immediate delivery planned. At that time rates enjoyed a very short-lived boom, similar to that which had taken place ten years earlier on the outbreak of hostilities between Iraq and Iran.

Analysts report that the number of VLCC liftings in the Arabian Gulf during October was well above the average, with both Saudi Arabia and – ironically – Iraq making additional volumes of oil available to the market. Some of this can be attributed to seasonal factors but there are clear indications that much of the extra oil coming onto the market was being bought in order to provide a stock cushion against potential supply disruption.

The effect on spot freight rates was heightened by the fact that, over the past year, the tanker supply position has tightened, especially in the larger ship sizes. According to analyst Poten & Partners, the VLCC/ULCC fleet (vessels over 200,000 dwt) has witnessed a net reduction of 14 ships over the past year, as the pace of scrapping has outstripped newbuilding activity. Shipbreaking often increases during times of weak earnings when it is uneconomic to keep older ships afloat, the trend has been further encouraged this year by the regulatory requirement to retire older, single-hull tankers.

A similar level of tightness is evident in the Suezmax sector (100,000 to 200,000 dwt) where there has been a general improvement in employment concentrated on an increase in liftings from West Africa for US and Mediterranean discharge. However, until the fourth quarter owners were unable to achieve any significant improvement in earnings. As well as reflecting a knock-on effect from VLCC rates, the Suezmax market was also boosted by rising exports from the Black Sea, an area that is generally off the radar for VLCCs.

This tightness trickled down to the Aframax sector, especially in the Caribbean where the market was upset by weather interruptions during October and November. On the other hand, there has been little impact on the product tanker sector, which has had a quiet year by comparison.

Threat of fleet growth

The question now is: 'Can this unexpected bounty for owners be maintained?' The fundamentals do not look

too good – the International Energy Agency (IAE) has revised its projection of global energy demand in 2002 and 2003 downwards, suggesting that the volume of crude oil to be lifted from the main export zones over the coming year will not support any fleet growth.

There were 20 VLCCs due for delivery in the fourth quarter, indicating that the net reduction in the fleet during the first nine months of the year would not be maintained over the year as a whole. The Aframax sector also has a large orderbook at present. Overall, the orderbook stands at the equivalent of 22% of the current fleet. Scrapping will certainly have to continue at its current high levels if the fleet as a whole is not to return to a position of substantial surplus.

According to data published by *Lloyd's Shipping Economist*, the tanker fleet as a whole, including combination carriers working in oil trades, stood at 270.4mn dwt at the end of August 2002. Over the previous 12 months there had been a net reduction of 10.9mn dwt. If scrapping continues at this rate, and based on the existing level of new orders, the fleet will be further reduced, reaching 258.9mn dwt by the end of 2004. Since publication of the report, however, a number of significant new orders have been placed for 2004 delivery, notably in the Aframax sector.

The potential for any increase in scrapping is limited, however – not only does this rely on the level of demand for scrap metal, notably in the Indian sub-continent, but the industry is also coming under closer scrutiny regarding its safety record and environmental impact. It cannot be any coincidence that the tanker industry has recently been attempting to change the perception of scrapping by promoting the environmental benefits of ship 'recycling'.

On balance, therefore, it would appear that the current market firmness is primarily a reaction to the supply threat arising from potential military action against Iraq and the disruption that such action could cause to oil supplies from the Middle East as a whole. On the model of previous, similar scenarios, the most likely outcome is a return to the more 'normal' levels of freight rates once any such military action takes place.

Security also costs

If tanker owners are currently enjoying an unexpected fillip in their earnings arising from security worries, then their costs are also being impacted by similar concerns. Indeed, the entire topic of 'security' has overtaken 'safety' and 'environmental protection' as the main driver behind regulatory imperatives since the 11 September 2001 attacks on the US.

Photo: Bergesen

Very large gas carriers have been pressed into service in the clean product trades

This has already brought about a disruption to the normal working patterns of companies, with greater focus having to be placed on operational aspects such as manning. In addition, oil market jitters have supported the oil price, keeping bunker fuel costs high, and – particularly since the *Limburg* incident – insurance costs have risen. Operators are also being required to carry out security risk assessments and, whereas in the initial phase it was anticipated that 'security' could be viewed as a sub-set of 'safety', it is becoming increasingly apparent that security requirements can often actively conflict with safety imperatives.

A balance needs to be struck between security onboard ship and in port on the one hand and, on the other, the free movement of vessels and the vital cargo they carry. Not surprisingly, the process has gone furthest in the US, with much greater oversight of seafarers – not only on foreign-flag ships – and control of their movement in the port area. Other port states are following suit. There is clearly a need for international action on security matters if the industry is not to be yet further disrupted by the need to take into account variations in national or regional requirements.

The environment still counts

While the International Maritime Organisation (IMO) has begun to look at security matters, much of the activity at the relevant committees and sub-committees this year has involved the continuation of work on environmental topics. At its October meeting, the Marine Environment Protection Committee (MEPC) made substantial progress on a number of issues, including ballast water management, ship recycling and anti-fouling paints. In addition, a number of states indicated that they were intending to ratify Annex VI to the International Convention for the Prevention of Pollution from Ships (Marpol) 1973/78, which aims to control the emission of greenhouse gases from ships. This suggests that the Annex will enter into force as expected some time during 2004.

Of the other issues mentioned, the most problematic for tanker owners will be ballast water management. This is an 'environmental' issue insofar as it aims to prevent the movement of non-native organisms into areas where they are likely to do harm to native species. From an operational point of view, however, it raises a safety issue in that tankers may be expected to discharge ballast water in open seas and continue to the load port in a potentially unstable condition. More work is to be carried out by the IMO next year.

Another important matter being progressed by MEPC's Sub-Committee on Bulk Liquids and Gases (BLG) is the long-running work to revise Annexes I and II of Marpol. From the operator's viewpoint, the importance of these Annexes is that they set limits on acceptable discharges from oil and chemical tankers, respectively. Work on Annex II in particular has been long and complex and, when it is eventually completed, could lead to a far-reaching change in the way that the chemical tanker fleet operates.

A number of coastal states are becoming increasingly active in the prosecution of illegal discharges of tank washings and oily water into their waters. However, there remains a lack of discharge facilities in many ports, despite this being a requirement of Marpol, and this is an area where states must take action if they are to expect vessels to be able to comply with restrictions on discharges at sea.

All in all, the short-term benefits to be reaped from the current spike in the tanker market seem slight compensation for the difficulties that owners are currently having to face. Once the market returns to normal there will surely be many who will be wondering if it is all worth the trouble.

Azpetrol petroleum rail tanks transiting Azerbaijan

Photo: David Hayes

South Caucasus gas in the pipeline

The South Caucasus Pipeline (SCP) gas project and Baku-Tbilisi-Ceyhan (BTC) oil pipeline are among the most important international pipeline projects to be tendered in 2002. They mark the launch of efforts to develop the huge oil and gas reserves under the Caspian Sea and transmit them to Europe and other markets through Turkey, which has ambitions to become the major transit route for Caspian oil and gas to Europe and the world market. *David Hayes* reports.

Contracts are due to be awarded shortly for the construction of the SCP project to transmit gas from Azerbaijan's offshore Shakh Deniz gas field through Georgia to Erzurum in eastern Turkey, from where it will be fed into Turkey's national gas transmission grid. Contract awards are also soon expected for the BTC oil pipeline that will transmit oil from Azerbaijan's offshore Azeri-Chirag-Gunashli (ACG) field through Georgia to Ceyhan on Turkey's Mediterranean coast for export.

Although the BTC project was officially launched in September, the culmination of eight years planning to develop an oil export route through the Caucasus to Europe, plans to build the SCP gas pipeline are still awaiting final approval. Indeed, a decision was pushed back a month to early November, as *Petroleum Review* went to press, in order to allow project leader BP to carry out a project design review.

Shakh Deniz speculation

Project approval delay has caused speculation that the 30tn cf Shakh Deniz development and accompanying SCP pipeline scheme may have run into difficulties following Turkey's economic downturn and lower than originally forecast gas demand growth. Turkey suspended imports of Iranian gas on 24 June 2002, claiming that the gas being supplied was of low quality. Although Turkey's Energy Minister, Zeki Cakan, was quoted as saying Turkey would resume Iranian gas imports once the quality was upgraded to contractual standards, Iran's Oil Minister, Bijan Namdar Zanganeh, has argued that the real reason for the stoppage is the slump in the Turkish economy.

The economic downturn has already led Turkey to negotiate a reduction in proposed gas imports from Russia through the Blue Stream gas pipeline that runs under the Black Sea from Russia to Turkey. In 2003 the country will import just 2bn cm through the Blue Stream pipeline, half the originally planned 4bn cm.

In August this year BP announced that the start date for gas deliveries from Shakh Deniz would be set back a year to 4Q2006 because the Turkish Government had yet to provide purchase gaurantees. More recently, in September, Ilham Aliev, Vice President of the State Oil Company of the Azeri Republic (SOCAR), said the delay was due to BP's cost estimate for the project rising from $2.7bn to $3.2bn.

SCP pipeline

It is possible that BP has launched a SCP pipeline design review as cost estimates have risen at a time when Turkey is negotiating to lower gas prices and import commitments due to the country's economic problems. While some of the Shakh Deniz gas may be intended for the Turkish domestic market, Turkey also plans to resell some of the gas to Europe. 'Turkey has assured us that they will live up to their contractual obligations,' commented a source in the BP-led project consortium. 'We believe they are pursuing a Greek pipeline link. Also they have made trips to see Ruhrgas.'

The SCP pipeline does not have a formal name yet and could be named the South Caucasus Pipeline Company. It is expected to remain in private ownership. Kvaerner is the main contractor for the defined design of the SCP pipeline; Brown & Root conducted the upstream design. 'We are still working with our partners to set up a structure for the pipeline company and the entity to sell the gas,' the consortium source said. 'We are finalising corporate structures and getting agreements set up. There is a lot of preparation for the sanctioning of the project such as due diligence. A lot of the agreements are unique as the SCP pipeline is being built in parallel to the BTC pipeline in order to realise cost savings.'

Plans call for gas and condensate from Shakh Deniz to be transmitted onshore through two 100-km subsea pipelines to Sangachal, south of Baku. One pipeline will carry gas, the other condensate. From Sangachal the SCP pipeline will run 970 km across Azerbaijan and Georgia into eastern Turkey to connect with Turkish gas transmission company BOTAS' national gas transmission grid at Erzurum. The subsea pipelines will be designed to carry 900mn cf/d initially. Turkey is due to take 660mn cf/d, while Georgia will buy 90mn cf/d. A further 150mn cf/d will be supplied to the domestic market in Azerbaijan.

Although the SCP pipeline is expected to carry over 8bn cm/y based on current contracts with Turkey and Georgia, it will be designed to eventually carry over three times this gas volume if more gas reserves are discov-

ered by BP or operators of other gas fields in Azerbaijan, or if neighbouring countries want to use the pipeline as an export route to Europe.

Azeri gas expansion

Developing the Shakh Deniz reserves will allow Azerbaijan to expand the use of gas for industrial purposes, including power generation, and for residential consumption. SOCAR, which is responsible for all oil and gas production in Azerbaijan and a member of the project consortium, will buy all Shakh Deniz gas destined for the Azeri domestic market, it will then sell the gas to state-run Azerigas to supply electricity companies, industrial users and residential customers.

The gas supply arrangements in Azerbaijan will consequently remain unchanged as SOCAR is responsible for buying all domestic gas production and gas imports that it sells to Azerigas. Onshore and offshore gas production, including associated gas from oil production, is currently estimated at about 500mn cf/d. In addition, Azerbaijan imports gas from Turkmenistan to fill the current shortfall in domestic gas production.

Azerbaijan's piped gas network consists of 4,500 km of high-pressure transmission pipelines and more than 31,000 km of medium and low-pressure distribution lines. About 80% of the 8mn Azeri population is estimated to have access to piped gas supplies.

Azerbaijan is planning to increase gas use with associated gas production from the ACG oil field and from Shakh Deniz. A five-year World Bank project to rehabilitate and upgrade the national gas transmission and distribution network is almost complete and will allow Azerigas to expand gas sales as supplies grow in the future. Some 2,600 km of pipelines have been rehabilitated with cathodic protection, while compressor facilities have been renewed and old gas meters replaced.

Foreign companies are among those interested in Azerbaijan's downstream gas industry. Apart from power generation opportunities, a number of chemical companies in Azerbaijan have attracted Japanese interest. Several plants could be upgraded and would use additional gas supplies.

The World Bank also is interested in plans to privatise Azerigas. However, the government has not made any decision so far.

Georgian plans

Meanwhile, Georgia intends to use gas supplies from the Shakh Deniz field for supplementing the present supply of high priced Russian gas imports. The

Photo: David Hayes

Socar's head office in Baku, Azerbaijan

Georgian Government sees the field as a source of reasonably priced, reliable gas supplies that will help stabilise the nation's energy supply, including power generation which presently is subject to seasonal variations causing power shortages and high tariffs.

Buying gas from Shakh Deniz will also reduce Georgia's dependency on Russia with which it has problematic relations. 'Under the SCP pipeline transit contract Georgia can buy up to 5% of the gas volumes passing through the country,' said the project consortium source. 'Nothing is standard in the contract except for a transit fee or right to buy gas. The actual details depend on the country's needs.'

Gas storage

As part of plans to use Shakh Deniz gas to stabilise Georgia's energy supply, GIOC – the state-run Georgia International Oil Company that is buying the Shakh Deniz gas – recently invited bids from US consultants to conduct a feasibility study on building an underground gas storage facility. Such storage facilities would minimise the adverse impact from disruption of gas deliveries from abroad while improving the security of natural gas supplies in the Caucasus region and optimising the economic value of natural gas received through the SCP pipeline.

Improving the reliability of gas supplies to provide reliable electricity in Georgia during the autumn and winter when hydropower resources are low has been a government goal since the early 1990s. Prior to the breakup of the USSR, the Caucasus republics of Georgia, Azerbaijan and Armenia operated as part of a unified gas supply grid that was dispatched from Moscow. The grid supplied gas from Russia during the autumn and winter to the gas-fired power plants in the three countries. The cost of the gas was repaid during the spring and summer months, when the three countries were able to export surplus hydroelectric power generation to Russia.

For a variety of reasons the Russians are no longer eager to continue this trade and Georgia, in particular, has suffered severe winter power shortages as a result. Because no gas storage facilities are available in Georgia, gas consumers have been forced to accept erratic service and high prices for the Russian gas.

GIOC's proposed gas storage project will allow gas to be purchased during the summer months when the price is at its lowest and ensure sufficient supplies are available in winter. Also, Georgia will be able to regulate its hydropower generation and sell surplus power at peak hours to neighbouring countries, which should help lower electricity prices for Georgian consumers.

Most of Georgia's national gas pipeline grid dates from the Soviet era and requires extensive modernisation. Gas is imported from Russia via a pipeline that forks in Georgia – one section crosses the border into Azerbaijan, the other section continues south to Armenia. However, as a diplomat in Tbilisi commented: 'Foreign gas companies are not interested in Russia and the Caucasus as the gas market in Armenia is not good and there are political sensitivities between Russia and Azerbaijan.' That said, Russia has offered to build an 80-km extension to the existing gas pipeline, from western Georgia near the Black Sea coast into eastern Turkey where the gas would be used to fuel a gas-fired power plant. Further details of the proposal were not available as *Petroleum Review* went to press.

DLO
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The Defence Fuels Group (DFG) is a multi-disciplined team responsible for the provision of all operational ground, aviation and marine fuels, packed and bulk lubricants, and industrial gases for use by the Armed Forces. Two exciting opportunities exist within the team based at West Moors.

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QUALIFICATIONS AND EXPERIENCE:

You must hold a second class Chemistry Honours degree plus four years' experience **OR** degree standard membership of professional institution plus relevant experience. Previous laboratory fuel and lubricant testing experience and trials and development work on aviation products (including specification writing) is essential. In addition, a broad-based scientific knowledge of petroleum products with specific knowledge of aviation products and their application is also essential. You must have good team working, planning, organising, communication, numeracy, IT, problem solving and decision-making skills and the ability to support your line management. You must also be able to use resources to achieve value for money and manage the provision of services and contractors effectively. Good staff management and development skills along with applying specialist or professional skills and knowledge are also essential.

FUELS HANDLING EQUIPMENT 3

BAND C2 - Reference PSC 15/03/54

You will act as the Engineering Authority for Compressed Gas Cylinders, and provide technical advice to MOD for compressed gas and certain aviation fuels equipment. You will also hold responsibility for the development and maintenance of a quality system for the management of Airworthiness within the DFG. Other tasks include the Fuels Handling Equipment (FHE) (Air) support to the acquisition process and key stakeholders and FHE (Air) support to Operations.

QUALIFICATIONS AND EXPERIENCE:

You must hold either Registered Incorporated Engineer (IEng) status **OR** Honours Degree (minimum 2:2) in a relevant mechanical engineering discipline plus two years' structured training or equivalent experience **OR** Pass Degree in a relevant mechanical engineering discipline plus two years' structured training or equivalent experience plus a minimum of three years' proven competence in an Engineering capacity **OR** HNC/HND in a relevant mechanical engineering discipline plus two years' structured training or equivalent experience plus a minimum of three years' proven competence in an engineering capacity **OR** NVQ/SVQ level 5 in a relevant mechanical engineering discipline. In addition, a broad-based aircraft/mechanical engineering background with experience of maintenance and engineering procedures is essential. You must have good team working, planning, organising, communication and IT skills along with the ability to use resources to achieve value for money and good staff management and development skills.

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A relocation package of up to £5,000 may be payable (if eligible).

BENEFITS INCLUDE:

- A choice between a final salary pension (with a contribution rate of 3.5%) and a defined contribution or 'Partnership' pension, giving you the flexibility to choose the pension that suits you the best.
- 25 days' annual leave, rising to 30 days after five years' service plus 10.5 days' public holidays and special leave provisions.
- Excellent training, development and advancement opportunities.
- Flexible working hours.
- Free on-site parking.
- Eligible for membership of the Officers' Mess.
- Opportunities to participate in sporting and social activities.

For an application form and job description please contact Mr Gary Brown on 01225 467950 or write to: DLO PSC Recruitment, Spur 8, Dyrham, Ensleigh, Bath BA1 5AB or e-mail your full name and address to psc.recruitment@dial.pipex.com

The closing date for applications is 13th December 2002.

Please note, that all information supplied to the MOD, in connection with this advertisement, will be treated in accordance with the Data Protection Act 1998.

The Ministry of Defence is an equal opportunity employer and is fully committed to equal opportunities policies. The Ministry of Defence positively welcomes applications from all sectors of the community irrespective of racial origin, sex or disability.

INVESTOR IN PEOPLE

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MINISTRY OF DEFENCE

NEWS Technology

Low-cost vapour pressure measurement

Testing the vapour pressure of gasolines and crude oil is important in defining their performance, safety and environmental properties and also contributes to assessment of fuel efficiency and thus fuel preservation. Well defined volatility characteristics exist that enable producers to manufacture automotive and aviation fuels with known driveability, combustion and efficiency performance.

The new Setavap 2 instrument from Stanhope-Seta reportedly 'revolutionises' the laborious Reid Bath RVP measurement process (ASTM D323 and equivalent methods) that is traditionally used to determine the vapour pressure of gasolines. It is claimed to provide a low cost, compact and automated means of testing vapour pressure and results obtained correlate with traditional RVP measurements. The unit conforms to international test methods, including ASTM D5191 and IP 394 and EN13016-1.

A test is reported to take typically less than four minutes and results do not rely on operator interpretation. A 3ml sample is injected through a septum into a vacuum chamber which is controlled at a test temperature of 37.8°C (100°F). The pressure inside the chamber is automatically monitored and once it has stabilised the resulting vapour pressure is displayed and the sample discharged.

T: +44 (0)1932 564391
F: +44 (0)1932 568363
e: sz@stanhope-seta.co.uk

Measuring flows in water depths to 3,000 metres

A new deepsea version of the Seastream subsea flowmeter, capable of operating to depths of 3,000 metres, is now available from Solartron.

Standard designs were previously only suitable for use to 1,500 metres and have been installed in more than 150 North Sea well management applications to date.

Seastream is based on a classical Venturi tube design and is reported to offer measurement accuracy of <±3%, or ±1% with calibration.

A low pressure loss across the meter ensures energy efficiency, with only short upstream pipe lengths required.

The new model is suitable for 10,000 psi rated systems. All meters are supplied complete with a differential pressure transmitter.

Subsea electrical connectors can be provided to match any third party interface system, states the company.

T: +44 (0)1388 773065
F: +44 (0)1388 773065

Non-weld cable transit frame unveiled

A new non-weld cable and pipe transit frame for the ship and offshore sector was recently unveiled by Roxtec. Suitable for newbuild and refit in marine vessels and offshore platforms the fully tested and certified GHM frames are claimed to avoid the need for expensive welding while increasing installation speed and safety.

Installation and sealing of the frame is entirely mechanical (see below). It has a generous 60 mm flange allowing round cornered holes to be cut to minimise possibilities of bulkhead cracks. The flange is either bolted or self tapped into the bulkhead and sealed by a concealed gasket. Much lighter than welded frames the GHM is also reported to reduce the weight of the vessel.

The ease and speed with which the frame can be installed is also reported to allow fitting or modification while a vessel is at sea or a rig is in operation. The frame is fully compatible with pre-terminated connectors, states the company, and, where desirable, the whole assembly could be pre-wired and offered up to the bulkhead as a complete assembly.

All of Roxtec transit systems are based on MultiDiameter Technology. This enables any diameter of cable or pipe, within the module's capacity, to be secured by the removal of the core and the right number of layers within the module (see inset). 'Each module ensures an adequate separation between services, but still enables a large number of cable or pipes to pass through a compact enclosure,' reports the company.

T: +44 (0)161 761 5280
F: +44 (0)161 763 6055
www.roxtec.co.uk

Less tiring paper chase

The new Document Control Module from Quality Systems International (QSI) is designed to integrate into any LIMS application in the laboratory, such as standard operating procedures (SOPs) or health and safety documentation normally held as PC files or even hard copy. For example, the SOP for a rarely used method could be made instantly available when a sample specification is detected that requires it.

Spreadsheets, word processor files or html files can all be handled by the module, which can create and maintain a convenient central repository for all the documents used by a laboratory.

QSI has also added special tools for document management not normally found in LIMS systems. For example, documents located on a server can be catalogued automatically into the document manager rather than registered manually.

T: +44 (0)1223 846464
F: +44 (0)1223 846485

A chill in the air

Thermal Engineering Systems has launched a new range of package water chillers claimed to offer the most cost-effective process cooling solutions to meet customers' specific needs.

The Rhoss Chillers cover a wide range, from 3 kW up to 1,500 kW and are suitable for cooling applications in the refining sector and in the manufacturing of chemicals, in both safe and hazardous areas. Although available off the shelf, bespoke designs can also be catered for.

T: +44 (0)1884 840216
e: **sales@thermal-eng.co.uk**

If you would like your new product releases to be considered for our *Technology News* pages, please send the relevant information and images to:
Kim Jackson, Associate Editor, *Petroleum Review*,
61 New Cavendish Street, London W1G 7AR, UK
or e: petrev@petroleum.co.uk

Membership News

NEW MEMBERS

Mr J O Akintola, London
Mr E E Akpodiete, Sterling Law Alliance
Mr P Bridges, Sembcorp Simon-Carves Ltd
Mr G Bueshel, Platts
Captain N J Collingwood, The Edge Group
Mr D L Creaney, Amalgamated Environmental Services Ltd
Mr P Denmead, Falmouth Oil Services (1994) Ltd
Mr K S Hancock, Wakefield
Mr N Hart, Matrix Software One Ltd
Mr K S Imuoha, Nigeria
Mr B Johnson, Atlas Environmental (NI) Ltd
Mr R Kingman, Guildford
Mr I J Land, Neston
Mr G Lawson, Coryton Commercials Ltd
Mr G E McCaughan, Amalgamated Environmental Services Ltd
Mr R Meech, Marine & Energy Consultancy Ltd
Mr A C Melmore, Orpington
Mr A Merali-Dewji, Northwood
Mrs M Morvan, Technip – Coflexip
Mr G A Moses, Aberdeen
Mr F Neysari, Leeds
Mr J Nicholls, Nottingham
Mr R Ogbomo, Nigeria
Dr W Robb, Proft Improvers Ltd
Mr D H Rodger, France
Mr S M Sanders, Bloomberg LP
Mr T Sarbanov, Harrow
Mr M E Solway, Nailsea
Mr G Stove, Radar World Ltd
Mr B Styles, Eco-Oil Limited
Mr N Ughamadu, Nigeria
Mr P Waine, Waste Oil Services Ltd
Mr J C Walter, Simmons & Simmons
Mr J Whelan, Petrus Oils Ltd
Mr D E A Williams, Deloitte & Touche

STUDENTS

Mr S G Alvis, Rayleigh
Mr L P Amin, Edinburgh
Mr P M Atkins, Open University
Mr E N Dortie, Dundee
Mr J A Hall, Birmingham
Mr K A Randall, Stanford-le-Hope

CORPORATE MEMBER

Scientifics Ltd, 500 London Road, Derby DE24 8BQ, UK
T: +44 (0)1332 264619 F: +44 (0)1332 264720
e: info@scientifics.com
www.scientifics.com
Representative: Alan Baker, Divisional Manager
Complete testing and consultancy organisation with its origins in British Rail. The company is now privatised employing 300 people across the UK in areas such as lubricating, transmission and transformer oils. Oils testing laboratories in Doncaster and Derby undertake oil condition monitoring programmes.

Branch Activities

ESSEX

Contact: *Arnold Carlson T: +44 (0)1268 794615*
8 Jan: *Waste Oil – Armageddon*, by Kevin Hollocks, Managing Director, Oikos Storage Ltd

LONDON

Contact: *Ian K Robinson T: +44 (0)1932 783774*
3 Dec: 1800: *Global/EU environmental legal issues* by Nigel Waterson, MP, Watson Farley and Williams Solicitors

ABERDEEN

Contact: *Vic Baxter, T: +44 (0)1224 587810*
10 Dec: *The use of ROV in the industry today*, by Greg McKenna, SonSub
14 Jan: *The future of corporate and profit finance for the UKCS*, by Tony Wood, Royal Bank of Scotland

NORTHERN

Contact: *Alan Holt T: +44 (0)161 875 3242*
5 Dec: Final Committee meeting of the year, and election of new President

STANLOW

Contact: *John Hinde T: +44 (0)151 342 1636*
26 Nov: AGM, followed by *Oil & gas in Liverpool Bay* – an update, (speaker invited from BHP)

Discussion Group

ENERGY, ECONOMICS, ENVIRONMENT

Small wind turbines – not just for fairy lights

Wednesday 4 December 17.00 for 17.30
Institute of Petroleum, 61 New Cavendish Street, London W1G 7AR
Speaker: **Leonard Magrill, FInstPet, Chairman, Iskra Wind Ltd**

Contact: **Laura Viscione** **e:** lviscione@petroleum.co.uk

NEW Publications

Economic Institutions and Environmental Policy*

Editors: Maurizio Franzini and Antonio Nicita (Ashgate Publishing, Gower House, Croft Road, Aldershot, Hampshire GU11 3HR, UK. **www.ashgate.com***) ISBN 1 84014 150 6. 240 pages. Price (hardback): £42.50.*

This book investigates the background to environmental economic development over the last 30 years, and the political implications of new directions resulting from technological and cultural changes in environmental issues. It examines the application of economic analysis to environmental problems in the past and solutions to the current issues of water, soil, air, energy, waste and urban ecology, discussing the implications of political decisions, cultural changes and technological constraints.

Handbook for Process Plant Project Engineers*

Peter Watermeyer (Professional Engineering Publishing, Northgate Avenue, Bury St Edmunds, Suffolk IP32 6BW, UK. T: +44 (0)1284 763277; F: +44 (0)1284 704006; **www.pepublishing.com***) ISBN 1 86058 370 9. 336 pages. Price (hardback): £59.*

This handbook systematically identifies the issues surrounding the effective linking of project management techniques and engineering applications. It is not a technical manual, nor is it procedure led. Instead, it encourages creative learning of project engineering methodology that can be applied and modified in different situations. While the book specifically addresses process plants, the principles are applicable to other types of engineering project where multi-disciplinary engineering skills are required, such as power plant and general factory construction. It focuses on the technical aspects that typically influence the configuration of the plant as whole, on the interface between the various disciplines involved, and the way in which work is done. It also develops an awareness of relationships with other parties – clients, suppliers, package contractors and construction managers – and of how the structure and management of these relationships impacts directly on the performance of the project engineer.

Handbook of Petroleum Product Analysis*

James G Speight (John Wiley & Sons, The Atrium, Southern Gate, Chichester, West Sussex PO19 8SQ, UK. T: +44 (0)1243 779777; F: +44 (0)1243 775878; e: **cs-books@wiley.co.uk***) ISBN 0 471 20346 7. 409 pages. Price (hardback): £92.95.*

An increasing variety of petroleum feedstocks has produced an ever diversifying array of petroleum products. Consequently, new analytical techniques are constantly being developed in order to determine the appropriate applications for these new products. This handbook provides detailed explanations of the necessary standard tests and procedures that are applicable to these products in order to determine the predictability of their behaviour. A companion to the author's *Handbook of Petroleum Analysis*, this book describes the application of methods for determining the instability and incompatibility of petroleum products. It also provides details of the meaning of various test results and how they might be applied to predict product behaviour. Products covered include naphtha, aviation fuel, kerosene, distillate fuel oil and asphalt.

** Held in IP Library*

Latest from the Library

YOUR OFFICE AWAY FROM HOME

Christmas Opening Times

The IP Library is usually open from 9.15am to 5pm, Monday to Friday. However, opening times will vary over the Christmas and New Year period:

19 Dec	Open 9.15am to 1pm only
20 Dec	9.15am to 5pm
23 Dec	9.15am to 5pm
24 Dec	9.15am to 12.30pm only
25–27 Dec	**Closed**
30 Dec	9.15am to 5pm
31 Dec	9.15am to 5pm
1 Jan	**Closed**
2 Jan	9.15am to 5pm
3 Jan	9.15am to 5pm

Back to normal hours from Monday 6 Jan.

New Editions to Library Stock

- *Floating production systems: A briefing paper from OGP.* International Association of Oil and Gas Producers (OGP), London, UK, 2002.
- *Flying the waves.* 1st Edition. Richard Pike. ISBN 190395309X. Woodfield Publishing, UK, 2002.
- *Global oil and nation state.* 1st Edition. Bernard Mommer. ISBN 0197300286. Oxford Institute for Energy Studies, Oxford University Press, Oxford, UK, 2002.
- *Natural gas in Asia: The challenges of growth in China, India, Japan and Korea.* David Fridley, Najeeb Jung, Akira Miyamoto, Keun-Wook Paik, Jonathan Stern and Ian Wybrew-Bond. ISBN 0197300294. Oxford Institute for Energy Studies, Oxford University Press, Oxford, UK, 2002.
- *Statistical review of global LP gas 2002.* Mch Oil & Gas Consultancy, World LP Gas Association, Nuthurst, UK, 2002.
- *Towards an energy policy.* Dieter Helm (ed). ISBN 1873484418. Oxford Economic Research Associates (OXERA), Oxford, UK, 2002.

Contact Details

- **Information, careers and educational literature queries to:**
  Chris Baker, Senior Information Officer, +44 (0)20 7467 7114
  Sally Ball, Information Officer, +44 (0)20 7467 7115
- **Library holdings and loans queries to:**
  Liliana El-Minyawi, LIS Assistant, +44 (0)20 7467 7113
- **LIS management queries to:**
  Catherine Cosgrove, Head of LIS, +44 (0)20 7467 7111
- **IFEG queries to:**
  Sally Ball, IFEG Secretary, +44 (0)20 7467 7115

Fax any of the above on +44 (0)20 7255 1472 or e: **lis@petroleum.co.uk** Visit our website at **www.petroleum.co.uk**

MOVES People

The Board of BP has announced that it has appointed **Dr Byron Grote** as Chief Financial Officer of the company. The appointment took effect on 21 November. Grote has succeeded **Dr John Buchanan** who is retiring from the Board. Grote was appointed an Executive Director of BP and Chief Executive of BP Chemicals in August 2000. He will retain responsibility for the Integrated Supply & Trading function and the Asia region while his responsibility for Chemicals will pass to Deputy Chief Executive **Rodney Chase**. Buchanan's Board responsibility for Australasia will pass to Exploration Chief Executive **Richard Olver**.

It has been announced that **John W McDonald** has become Corporate Vice President of ChevronTexaco. The appointment took effect on 1 November. McDonald, who joined the company in 1975, most recently served as Managing Director of the European business unit of ChevronTexaco Overseas Petroleum and was based in London and Aberdeen. From 1996 to 1998 he was Vice President of Exploration & Production, Offshore Division, located in New Orleans. McDonald replaces **Patricia Yarrington** who was recently named Vice President, Public and Government Affairs. Yarrington replaces **Rosemary Moore** who resigned to accept the post of Senior Vice President, Corporate Affairs for UAL. She will report directly to Chairman and Chief Executive Officer **David J O'Reilly**.

Sibneft has appointed **John A Mann II** as its new Head of International Media Relations. Mann previously worked as Vice President and Client Service Director of the Willard Group/Burson-Marstellar, the CIS affiliate of the international public relations consulting group.

Petroleum Geo-Services has announced that, following the Chief Executive Officer (CEO) succession plan reported in August, **Svein Rennemo** has been appointed CEO of the company with effect from 7 November. Rennemo has held the position of partner in Econ Management Consulting as well as Chief Executive Officer of Borealis Petrochemicals. He succeeded **Reidar Michaelsen**.

Vector International has appointed **Ian Kennedy** as Branch Manager of its Aberdeen office. Kennedy has a strong background in engineering and experience of the oil and gas industry, more recently as General Manager of MSI Oilfeed Products in Aberdeen. He succeeds **Jim Fraser** who retired in July after 12 years with the company.

Expro International has announced two new appointments to the Board with immediate effect. **Roger Boyes** joins as a non-Executive Director. Previously Finance Director with the Halifax Group, Boyes has experience of the Finance Service Industry together with a background in the international engineering sector. **Mike Martindale** joins as Executive Director Eastern Hemisphere. He joined the group in 1995 and has over 30 years' experience in the oil and gas industry, gained with operators such as Shell and Texaco.

Andy Elliott has been appointed Country Operations Manager – Indonesia for BJ Tubular Services. Elliott was previously employed by Premier Oilfield Services of Aberdeen as Manager of the company's base in Great Yarmouth and Continental Europe Manager in Holland.

Mike Straughen, Chief Operating Officer of Amec's Oil and Gas Petrochemicals operations, has been appointed to the position of Chairman of the Energy Industries Council (EIC). The Council is one of the UK's largest trade associations and represents UK-based companies that provide services to energy industries worldwide. Straughen will head the EIC's Board of Directors during his two-year tenure in addition to his responsibilities for Amec. He succeeds **Paul Barron** CBE.

Mike Fynes has been appointed Sales & Marketing Manager at Smith Flow Control. He joins the company from Columbus IT Partners UK. Fynes has over 26 years' experience with the Halma Group, previously holding senior sales and marketing positions for Fortress Interlocks, Castell Safety and Ellis Interlocks in the UK and Castell Inc in the US.

Ofgem has appointed **Sonia Brown** as Director of Electricity Trading Arrangements. She will be responsible for overseeing the trading arrangements including modifications to Neta's Balancing and Settlement Code, Transmission Access and System Operator incentives.

Ramco Energy has appointed **Vikram Lall** as a non-Executive Director to the Board. Lall replaced **David Boyle** who retired on 1 October. **Michael Seymour**, Exploration Director of Ramco also retired on 30 September.

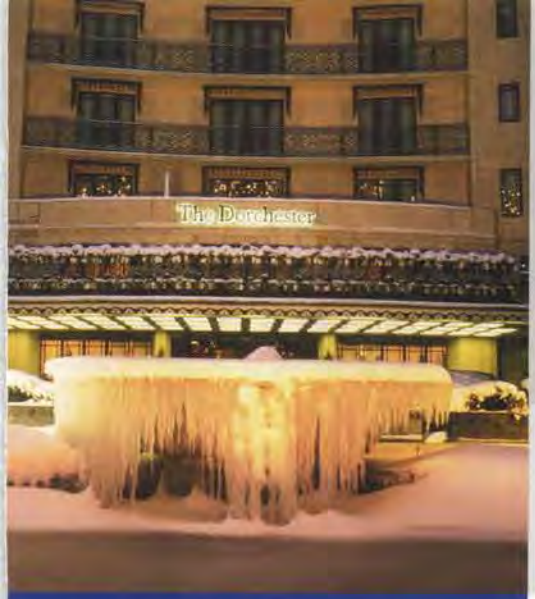
Following the Moscow Refinery's EGM, where Sibneft won full control with Tatneft's support, the new Board of Directors has appointed **Sergei Ilyin** as the new General Director of the Moscow Refinery.

Derek Sinclair has been promoted to Managing Director, UK of Nutec. Sinclair was formerly Operations Director with the company.

NEXT MONTH'S FEATURES...

The January 2003 issue of *Petroleum Review* will review oil and gas prospects for the coming year, including a closer look at the US market, opportunities in the global gas-to-liquids sector and analysis of the Nigerian E&P arena. It will also include an article on current disaster recovery programmes, of particular relevance as Middle East tensions continue to rise, and a case study review on BP's use of reverse auctions in its UKCS supply chain management strategy.

The winners of the 2002 IP Awards will also be showcasing their prize-winning projects. There will also be a round-up of the findings of the Gas Market Workshop, recently held at the Institute of Petroleum in association with Deloitte Petroleum Services. Don't forget to check out our new recruitment section. See contents page for details.



THE INSTITUTE OF PETROLEUM

Annual Lunch

Tuesday 18 February 2003, 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
David J O'Reilly
Chairman and Chief Executive Officer, ChevronTexaco

David J. O'Reilly was born in Dublin in 1947 and graduated in 1968 with a Bsc in Chemical Engineering from University College, Dublin. He then began his career with Chevron Research as a process engineer and in 1986 was named general manager of Chevron's refinery at El Segundo, California. His other management roles include: manager of manufacturing for Chevron Chemical's Olefins Division, Houston; manager of the Salt Lake refinery; manager of the agricultural chemicals plant, Richmond, California; and on the corporate foreign operations staff. In July 1989, he was elected Senior Vice President and COO of Chevron Chemical following on with a role as a Vice President of Chevron Corporation in October 1991. He also served as a director of Caltex Petroleum from March 1992 until September 1994. He was then elected President of Chevron Products with responsibility for the company's US refining and marketing operations. In November 1998, he was elected Vice Chairman to the Board of Chevron Corporation. He assumed his current position upon the formation of ChevronTexaco Corporation in October 2001.

For more information on this and other IP Week 2003 events, please visit:

www.ipweek.co.uk

THE INSTITUTE OF PETROLEUM

TICKET APPLICATION FORM

Please photocopy this page and send completed form to the Conference Department, The Institute of Petroleum, 61 New Cavendish Street, London W1G 7AR, UK Fax: +44 (0) 20 7580 2230

I wish to order ..... ticket(s) @ £145.00 + 17.5% VAT (£25.38) each = Total £ .....

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

IP Membership No: ..... Company: .....

Address: .....

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

E-mail: .....

Tel: ..... Fax: .....

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 Institute of Petroleum, 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: .....

.....

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

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

Data Protection Act 1998
Any information provided by you may be held by the IP in its computer records. Please tick if you do not want to receive details of products or services from other organisations with whom we associate. ❑

- Tickets can be purchased by Members and Non-Members of the Institute of Petroleum (IP).
- The cost of one tickets is £145 plus £25.38 VAT 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 IP, 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 requirements will be accommodated if notified to the IP by 7 February 2003. An additional charge may be incurred.
- Guests' names should be submitted in writing to the IP by Wednesday 29 January 2003 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, as well as the Tuesday Morning and Tuesday Afternoon Passes.
- If you cancel your order, a refund, less a 20% administration charge of the total monies paid will be made provided that notice of cancellation is received in writing on or before 6 January 2003.
  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 and in the General Information. Upon IP receiving your booking form (by fax, post or e-mail) 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.

IP THE INSTITUTE OF PETROLEUM

www.ipweek.co.uk

IP WEEK 2003

17 – 20 February, London

The Institute of Petroleum's IP Week is the focal point in Europe each year when leading figures in the oil and gas industry meet in London for an intensive round of conferences, industry and trade association events, company meetings and social functions. The Institute's own programme of events forms the core of these activities.

The week will include conferences focusing on:

- **Energy Price Risk**
- **Future of Gas**
- **Energy Supply**
- **Refining and Marketing**
- **EU Initiatives Affecting the Industry**
- **UK Upstream Industry**
- **Exploration**
- **Bunkers**
- **Oil and Gas in the FSU**

Selected IP Week 2003 events are organised in partnership with/sponsored by:

europia · New York Mercantile Exchange · WOOD MACKENZIE · IPIECA · IBIA · UKOOA · KBC · IHS ENERGY GROUP · BUNKER NEWS · gas

IP ANNUAL LUNCH

Tuesday 18 February, Dorchester Hotel, London

The IP 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:

David O'Reilly, Chairman and CEO, ChevronTexaco

IP ANNUAL DINNER

Wednesday 19 February,
Grosvenor House Hotel, London

The Institute of Petroleum's 89th Annual Dinner is a unique event in the international petroleum industry, which brings together over 1500 of its leading figures, and provides an opportunity to meet with old friends and acquaintances.

Guest of Honour and Speaker:

Philip Watts, Chairman, Shell

EXHIBITION

17 - 20 February, London

Maximise on business and promotional opportunities connected with IP Week 2003 by participating in the oil and gas information services exhibition. The exhibition will be held alongside IP Week 2003 events.

The AAPG is honoured to announce its second presentation of the APPEX-London prospect and property exhibition at the IP Week program. Information on exhibiting or viewing at APPEX-London will shortly be available at either **www.ipweek.co.uk** or at **www.aapg.org**

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

For more information on any IP Week 2003 event, contact the IP Conference Department:
Tel: +44 (0)20 7467 7100 e: events@petroleum.co.uk or see: www.ipweek.co.uk