Petroleum review

APRIL 2001

Russia and Caspian Survey

LNG trade

- Radical changes afoot

US electricity deregulation

- A Titanic disaster

Refining

- The challenge of tighter specs

Covering the international oil and gas industry from field to forecourt – exploration, production, refining, marketing and e-business

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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: The BP-operated Chirag 1 platform offshore Azerbaijan is currently producing around 110,000 b/d from AIOC's Azeri-Chirag-Gunesheli field. Production is expected to reach 120–130,000 b/d later this year.

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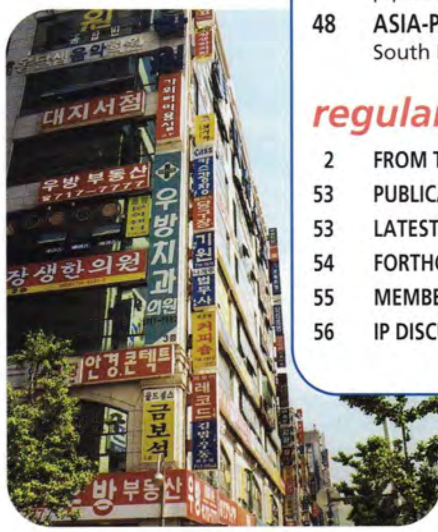


ROUNDUP From the Editor

Opec cuts undermined by Iraqi expansion

Once again, Opec has agreed to cut production – this time by 1mn b/d – in order to achieve its price objectives. Its target price range may be $22–28/b but many Opec members now seem to be unofficially aiming for around $30/b oil. At a time when Opec has achieved effective cohesion one can understand its desire to impose oil prices that cover all its governments expenditure plans. But if two cliches in one sentence are ever pardonable, it is not crying wolf for oil consumers to point out that Opec's price aspirations risk killing the golden goose.

So far, their aspirations have been undermined by Iraq which has been expanding production as the rest of Opec has been cutting it. In February, Iraq produced 2.1mn b/d, nearly 0.5mn b/d below year earlier figures and over 1mn b/d below its likely capacity. Opec and Iraq appear locked in a dangerous and very high stakes game at a time when the threat of a global economic slowdown is very real and when oil demand forecasts are being repeatedly revised down.

The latest (March) projection from the International Energy Agency (IEA) for 2001 oil demand increase has been revised down a further 110,000 b/d to 1.46mn b/d. This produces the mind twisting idea that Opec is prepared to risk global economic prosperity in pursuit of higher prices but Iraq is saving the day by producing more – providing western sanctions don't stop it.

Brazilian tragedy

The explosion and sinking of the Brazilian floating production unit P-36 on the Roncador field is a two-fold tragedy. For the casualties the tragedy is obvious, and all the industry would wish to extend sympathy to the injured and the bereaved. For the industry, however, the accident will cast a long shadow over deepwater production until the exact mechanism of the accident is known and understood – even then it is likely to produce fresh demands for additional legislation and control.

The impact of new legislation, even when desirable, can have severe impacts on production. Following the Piper Alpha accident in 1988, regulations were changed and inspections stiffened. The North Sea is probably a safer province as a result, but UK sector production was severely constrained as field installations were taken out of commission to install modifications. The production level achieved in 1987 was not exceeded until 1994 as a direct result.

Vanishing gas bubble

Just a few years ago it was confidently predicted that the UK would suffer/enjoy a 'gas bubble' that would last until 2005/2006. Indeed, the prospect of production capacity exceeding demand was one of the justifications for the building of the Interconnector pipeline from Bacton to Zeebrugge. It was certainly the explanation for installing a larger export capacity and a smaller import capacity. Although flows are not public knowledge, it is generally believed that Interconnector flows have never approached capacity in either direction.

The Interconnector's main impact has been a market impact (see p46). For the moment, UK sector gas production is still growing – achieving a record output in January 2001 of 13.06bn cf/d (see table p6).

There is a growing perception, however, that further gains are becoming more difficult. The recent NW Bell, Skiff and Vixen gas fields were all brought onstream in record time, while the recently sanctioned Brigantine A, B and C, together with Nuggets 1, 2 and 3 developments, also appear to be on accelerated timetables. The day when the Interconnector consistently becomes an import pipeline are approaching fast, with 2002/2003 looking a lot more likely than 2005/2006.

Straw in the wind

There is a widely held, but erroneous, belief that gasoline (petrol) demand is set to rise because improving efficiency will be offset by increased distances driven. It is, however, a myth.

In virtually all developed countries, gasoline demand is now static or weakening. The UK has just chalked up its eighth successive year of petrol sales declines (see *RMS* p16). The official figures of UK demand in 2000 show a radical new development – the first ever decline in diesel (Derv) sales. The decline was small (0.8%) and confined to the commercial sector (lorries, trucks and vans) rather than the retail market (cars). Nevertheless, it is a straw in the wind. Demand cannot be taken for granted. If taxes or prices are too high the consumer will find a way to use less. Environmentalists may be delighted – the UK Treasury and the oil companies rather less so.

Chris Skrebowski

e world

Common Data Access (CDA) has unveiled Phase 2 of the Deal web-based service (**www.ukdeal.co.uk**) that allows users to access information related to exploration and production activities on the UK Continental Shelf. New data sets have been added to the site and selected data is also now directly downloadable in digital format.

The educational part of the IP's website (**www.petroleum.co.uk**) was recently chosen as 'Site of the Day' on **www.schoolsnet.com** – a school guide listing of the best educational sites to be found on the Internet. The IP website as a whole is currently being revamped. The new and improved site will be launched soon…

Smartbunkers, the business-to-business (B2B) bunker exchange, has signed exclusive partnerships with two leading providers of commercial research for the marine and energy industries. MRC and Infospectrum will deliver online credit support facilities for registered bunker suppliers on the Smartbunkers exchange. The service will allow suppliers to order online credit reports on over 1,000 bunker buyers already registered with Smartbunkers directly to their desktop, via the website **www.smartbunkers.com**

The bunker exchange has also announced a new online credit insurance facility – SmartSure – designed to protect registered suppliers against the risk of non-payment by ship operators. It is reported that seven of the world's major international bunker traders – Bominflot, Cockett Marine Oil, Dan Bunkering, KPI-Oil Shipping, MOBCO (Marine Oil Trading), OW Bunker & Trading, and Tramp Oil & Marine – are to participate as sellers on the site.

informed professionals online
www.petroleum.co.uk

We are planning to launch the Institute of Petroleums' new and improved website later this month.

Although our existing site at **www.petroleum.co.uk** already contains a wealth of oil, gas and energy industry information, the site has been revamped to make it even more user-friendly and topical.

We are sure all you IP surfers will appreciate the benefits derived from the new site and welcome any suggestions you have for further improvements.

In Brief

UK

***A successful well test has confirmed** the commercial potential of BP's high pressure/high temperature Rhum gas field in block 3/29a in the northern North Sea, it has been reported. The well tested at up to 45mn cf/d with a low condensate gas ratio.*

***BP reportedly has plans to drill an** appraisal well on the Devenick field in the southeast of the Harding field in the northern North Sea. This is an attempt to firm up reserve estimates of 1tn cf of gas for the area.*

***TotalFinaElf has been given consent by** the UK authorities for the development of the Nuggets N2 and N3 natural gas fields, located in the UK sector of the North Sea, 400 km east of Aberdeen. The plans call for subsea wells to be tied back via a pipeline to the Alwyn North facilities.*

***Enterprise Energy Ireland (45% operator)** and their co-venturers Statoil Exploration Ireland (36.5%) together with Marathon Petroleum Hibernia (18.5%) have approved the development of the Corrib gas field located 70 km off the coast of County Mayo in Ireland.*

***Talisman Energy is reportedly planning** to develop the Halley field, located in the central North Sea. The field contains an estimated 11mn boe of reserves and is expected to produce 18,000 b/d of oil and 31.5mn cf/d of gas for five years.*

***Enterprise Oil has concluded successful** drilling on the Howe prospect in the North Sea. Preliminary estimates of hydrocarbons indicate between 30mn and 55mn barrels of reserves.*

***Talisman Energy's Beauly field has** reportedly begun production with an initial flow rate of 12,000 b/d. The field has estimated recoverable reserves of 3mn barrels of oil and has been developed with a single horizontal well tied back to the nearby Balmoral floating production vessel.*

Europe

***Kvaerner Oil and Gas has been** awarded a contract by Norsk Hydro to build the 5,500-tonne power generation module and living quarters for the North Sea Grane platform. Delivery is slated for May 2003.*

Minor budget changes for North Sea operators

No major changes were made to the offshore oil and gas taxation regime in the UK March 2001 Budget – a move much 'welcomed' by the UK Offshore Operators Association (UKOOA) and the UK Oil and Gas Industry Leadership Team (ILT).

Two petroleum revenue tax (PRT) loopholes relating to expenditure on decommissioning oil installations were closed however. These loopholes arose from a transfer of an interest in an oil field from one company to another, or from transfers of interests in infrastructure that had been shared between two or more oil fields. Now, when an interest in an oil field is transferred to another person, the amount of unrelievable field loss (UFL) that can be generated by a particular field will be capped to the amount of UFL that would have arisen had no transfer occurred. Furthermore, when an interest transfer is made, the new participator is to be treated as inheriting the PRT history of the field. However, it will be possible for the old and new participants to elect to jointly disapply the rule, so that the new participator does not inherit the PRT history.

In addition, PRT relief was extended in respect of decommissioning installations in fields producing gas, which was exempt from PRT, to take fairer account of the use of those installations by other fields in return for tariffs which were liable to PRT.

Also, a change has been made to the coming into effect of the measure announced in 7 August 2000 to make capital allowances available for the costs of preparing oil installations for reuse, and removing and mothballing them when their eventual fate is unknown. This measure has now been extended to apply to all such expenditure incurred in connection with an abandonment programme approved on or after that date.

Green light for Nam Con Son project

BP reports that the $1.3bn Nam Con Son gas project offshore Vietnam is set to go ahead. It is claimed to be the country's largest foreign investment to date and its first dedicated gas-to-power project.

The project centres around the development of 2tn cf of gas from the offshore Lan Tay and Lan Do fields which is to be brought ashore by pipeline and used by three generating plants to provide electricity primarily for consumption in the Ho Chi Minh City area. The electricity generated represents some 40% of Vietnam's current demand.

Construction is soon to begin on a steel production platform, as well as a new onshore gas processing terminal and a 360-km pipeline. The pipeline is designed to accommodate future gas supplies from the Nam Con Son Basin, including the Hai Thach field.

BP acts as operator of the Lan Tay and Lan Do gas fields, holding 26.67% equity. India's Oil and Natural Gas Corporation holds a further 45%, Statoil 13.33% and PetroVietnam 15%. BP is also to act as operator of the gas pipeline with 32.67% equity. The other pipeline partners are Statoil (16.33%) and PetroVietnam (51%).

Australian crude oil output on the decline

Barry Jones, Executive Director of the Australian Petroleum Production and Exploration Association (APPEA), has said that the Australian oil industry is facing a major decline in crude oil production within the next 10 years. He added that without large commercially practicable oil discoveries there would be sizeable consequences for the country's balance of payments and for the budgetary situation of the Commonwealth Government and some of the State Governments such as Western and South Australia. He went on to emphasise the need for Australia to find substantial quantities of oil very soon to offset the major decline that government forecasts are predicting.

A detailed examination of the location of proposed activity showed some disturbing trends. Most of the exploration activity is centred at present, in the more mature areas such as the Cooper/Eromanga Basin in northeast South Australia and southwest Queensland and in the Carnarvon Basin on the country's northwest shelf. There is very little activity in frontier areas offshore and little or no activity in areas subject to native title claims.

Qatari gas export agreement signed

An agreement has been signed to export 2bn cf/d of Qatari natural gas to the United Arab Emirates and Oman as part of the Dolphin project. The project aims to meet the anticipated steep rise in demand for gas in the UAE and Oman, particularly for power generation in the two countries. It includes:

- **Developing natural gas reserves in two blocks of Qatar's offshore North field. The first delineation wells are slated to be drilled in the 2H2001 and to come onstream in 2005.**
- **Building a 48-inch diameter, 350-km long pipeline linking a processing plant in Ras Laffan, Qatar, to the Taweeleh terminal in Abu Dhabi and the Jebel Ali terminal in Dubai.**

TotalFinaElf, which holds a 24.5% stake in the project, is to operate the upstream phase of the development plan, with Enron (24.5%) focusing on gas transportation. UAE Offsets Group holds the remaining 51%.

The cost of the initial phase of the Dolphin project is put at $3.5bn. A second development phase will cover the delivery of a further 1bn cf/d of gas.

Words of warning from new coal mine methane group

The UK Government has been advised that it could fail to meet its target of generating 10% of electricity from renewable energy by 2010 unless it encourages the development of more coal mine methane (CMM) projects. The words of warning came from Dr Cameron Davies, at the launch of the Association of Coal Mine Methane Operators (ACMMO) in March. The Association represents 13 companies involved with the extraction of methane from disused coal mines for use in power generation.

Davies, who is Chairman of ACMMO and Executive Chairman of Alkane Energy, also reported that the 'young industry was already supplying sufficient methane for 30 MW of distributed electricity generation and, as a result, capturing emissions equivalent to the removal of about 160,000 cars from the roads.' The methane is being captured at five sites across the East and West Midlands and Yorkshire. A further eight projects are due to come onstream by the end of the year.

There are over 900 disused deep coal mines in the UK. Companies in the industry are expected to start by developing projects with the largest reserves, each sufficient to product between 6 MW and 9 MW. However, according to ACMMO, with the right incentives in place there would be no reason why smaller sites generating around 2 MW to 3 MW should not also be tapped. This could lead to as many as 20 projects being built annually, so that by 2005 the total generating capacity could reach 750 MW – more than the total capacity of renewables installed up to 1998, excluding large scale hydro.

According to Davies: 'Everyone recognises the benefits of what we are doing, tapping gas that is already seeping out of the ground at the rate of some 300,000 t/y, reducing its global warming potential by 87%, using a waste product to generate electricity and so reducing the amount of natural gas, coal or oil having to be used. And yet we are also told that unlike methane from landfill, coal mine methane cannot be classified as a renewable source and be included in the renewables obligation. Even more anomalous, whilst CMM generated electricity supplied directly to end users as burner tip fuel is exempt from climate change levy, where it is supplied for distributed power generation it is not exempt.'

He stated that without assistance equivalent to about 3 p/kWh arising from inclusion in the renewables obligation and exemption from the climate change levy, only the most commercially viable sites would be developed. As a result, a 'huge' amount of CMM would continue to escape into the atmosphere, 'with all that means in terms of carbon emissions, hazards for people living in coalfield areas and the extra use of fossil fuel to generate electricity that otherwise could have come from the use of this waste product of past mining activity.'

Looking to the future, Davies said: 'Let us hope that action follows that helps us to develop many more sites, reduce harmful emissions and bring much needed investment to coalfield areas. There aren't many industries that do not have a downside; especially those involved with power generation. I think that we can honestly claim that ours is an exception.'

In Brief

Statoil is understood to have secured *partner approval for the development of the North Sea Mikkel field as a subsea tie-back to the Asgard B floating production unit.*

Repsol has discovered oil in the *Mediterranean, offshore Tarragona, Spain. The discovery well, Chipirón-NE, produced 8,000 b/d of oil. The well is expected to come onstream in 2H2001.*

Statoil has reportedly posted a record *pre-tax profit for 2000 of NKr38bn ($4.2bn), an increase of 138% on 1999.*

North America

J Ray McDermott is reported to have won *a turnkey engineering, procurement, construction and installation contract to provide a spar platform for Murphy Oil's Medusa field in the Gulf of Mexico.*

PanCanadian Petroleum has reportedly *approved the C$1bn commercial development of the Deep Panuke natural gas field located 250 km offshore Halifax, Nova Scotia. Following start-up in early 2005, gas production sales are expected to be 400mn cfld. The field contains recoverable reserves of 1tn cf.*

Coflexip Stena Offshore (CSO) has *reportedly secured a fabrication contract to supply up to five spar floating production platforms for BP's deepwater field developments in the Gulf of Mexico. The first spar is due for delivery in 2003.*

Middle East

Petroleum Development Oman (PDO) *is reported to have discovered what it claims is potentially the largest gas field in Oman for the past six years. The Kauther field is located in the al-Dakhlia region.*

Sheer Energy of Canada is reported to *have signed a buyback deal with the National Iranian Oil Company (NIOC) for the development of the Masjedi-Suleyman oil field in Iran. Recoverable reserves are put at over 6bn barrels.*

Snamprogetti of Italy is reported to *have secured a $140mn contract from Saudi Arabian Oil Company to build a gas/oil separation plant (GOSP) to boost production at Haradh.*

Tatneft has received permission from *the UN sanctions committee to drill 43 exploration wells in northern Iraq.*

In Brief

***The Saudi Government is to study with** seven international firms ways of developing gas fields in the Rub Al-Khali areas of the Jawabor region in southern Saudi Arabia. The company is seeking $25bn investment in the region, writes* Stella Zenkovich.

Russia & Central Asia

***Yukos has announced an increase in** proven reserves to 16.5bn barrels as of 31 December 2000, up 43% from 11.5bn barrels in 2000. As a result, the company is set to become the largest holder of crude reserves in Russia.*

***The Iraqi Government, according to** UFG, said that it might end contracts with Russian companies if they fail to start work on them. Russian companies are reluctant to do so due to UN regulations on activity in the area. Slavneft however, has just initialled a contract to develop the Subba oil field while Zarubezhneft has been given permission to drill 45 wells in northern Iraq as part of an agreement programme to increase Iraqi oil production.*

***The Russian Government has released** February 2001 oil production statistics showing production was 7.3% higher than in the same period last year. UFG forecasts a 4% increase in production in Russia in 2001.*

***Yukos and Sibneft have submitted a** joint bid for Val Gamburts production block in the Nenets district, according to UFG. The field contains a likely 600mn barrels of recoverable reserves.*

***An oil and gas field with estimated** reserves of 40mn tonnes of oil and 100bn cm of gas is reported to have been found in Russia's Republic of Birobidjan, writes* Stella Zenkovich.

Asia-Pacific

***Phillips Petroleum and El Paso are** reported to have signed a Letter of Intent to deliver 4.8mn t/y of LNG to markets in southern California and Mexico's Baja Peninsula from 2005. El Paso would buy the LNG from a plant to be built by Phillips near Darwin, Australia. The LNG plant will be supplied with gas from the Greater Sunrise fields in the Timor Sea, which contain approximately 9tn cf of gas.*

***Woodside Petroleum has agreed to** transfer a 16.39% interest in the Greater Sunrise fields to Phillips STL Proprietary.*

Fall in UK production claimed only temporary

UK oil production fell by 5.2% during January 2001 to its lowest level for that month since 1993, according to the latest Royal Bank of Scotland *Oil and Gas Index*. However, the Bank's Head of Business Economics, Stephen Boyle, states that this does not signify a declining North Sea oil industry. 'Some of the fields in which output has fallen are in long-term decline,' he said, 'but for many others the decrease in production is temporary and will be reversed. Output is likely to rise in 2001 as new fields come onstream and many existing fields see production rise.'

Oil production declined by 124,000 b/d on the month, and by 371,000 b/d, or 14%, since January last year. Average daily output in the 12 months to January 2001 was 9.2% less than in the 12 months to January 2000. It was a very different story for gas production, however, which has seen increases on both the month and the year. This January's production reached its highest level since December 1999 and rose by 14.2% on the previous month. Compared with January 2000, output was 1.1% higher. Average daily production in the year to January 2001 was 8.7% higher than in the year to January 2000.

Combined oil and gas output increased by 161,000 of oil equivalent per day to its highest level since April 2000, a rise of 3.7% on December. On an annual basis, output fell by 7%.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Jan 2000	2,645,841	12,913	25.63
Feb	2,567,535	12,743	27.97
Mar	2,606,250	12,485	27.27
Apr	2,480,945	12,149	23.15
May	2,222,686	9,089	24.15
Jun	2,436,450	8,609	30.50
Jul	2,383,944	7,531	28.90
Aug	2,339,363	7,464	31.60
Sep	2,281,516	8,080	33.70
Oct	2,247,307	10,172	30.90
Nov	3,322,296	11,621	32.80
Dec	2,399,038	11,439	26.30
Jan 2001	2,274,671	13,061	25.80

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Congo success for Heritage Oil

Heritage Oil has announced a successful onshore well in the Republic of Congo with the drilling of Kouakouala No 2. Logs have confirmed 54 metres oil column in a high quality reservoir which appears to possess consistent reservoir characteristics and common oil/water contact with the Kouakouala No 1 well. Kouakouala No 2 is to be completed and tied back to the main production facilities for testing and as a future producer.

The No 1 well entered production in May 2000 and has, to data, produced over 135,000 barrels of 39° API oil. Existing export/sales capacity have been restricted by the limitations of trucking operations. A third appraisal/development well is soon to be drilled and a new export pipeline completed which, in turn, will lead to substantially higher production for the Kouakouala field.

NEWS Upstream

North Sea news

Stephen Byers, UK Secretary of State for Trade and Industry, has launched the Beatrice Redevelopment Project, which aims to rejuvenate Talisman's Beatrice oil field offshore Inverness, safeguarding 60 long-term jobs and creating up to 650 jobs during the investment phase.

The government has also approved the company's Hannay oil development project in the North Sea. Hannay will be developed via a subsea satellite tieback to the Buchan-Alpha platform, which should extend the life of the field by up to 10 years. The two new projects will cost the company £65mn in investments.

Drilling in Iran

Shell reports that it has started drilling in the Soroosh field in the shallow waters offshore Iran. The company plans to drill 10 new horizontal production wells and two water disposal wells as part of the redevelopment of the Soroosh and Nowrooz fields.

Oil reserves are put at 500mn barrels for Soroosh and 550mn barrels for Nowrooz. Full production levels are expected to reach 100,000 b/d and 90,000 b/d respectively.

Early production from Soroosh is slated for end-August 2001 and full production from both fields in 2003.

Heritage Oil subsidiary Heramac has *been awarded six new licences onshore the State of Gujarat, India. Heramac holds a 30% stake in the six licences and is to act as operator of four. Partners are Gujarat State Petroleum Corporation (GSPC) and Hindustan Oil Exploration Company (HOEC), the latter acting as operator of the remaining two licences.*

Repsol YPF has discovered three new *fields in the West Madura block, offshore eastern Java, in Indonesia. A total of 6,300 b/d of oil and condensate, and 30.1mn cf/d of natural gas flowed during production tests. Preliminary estimates of recoverable reserves for the three fields are 13mn barrels of oil and condensate, and over 153bn cf of gas. The KE-23 oil field will be developed using existing production facilities in the area. First oil is slated for 3Q2001.*

ExxonMobil and Phillips Petroleum are *reported to have reached agreement with the North West Shelf Project partners to develop the Perseus and Athena gas fields as part of the project.*

Australian independent Santos has *reported its first oil discovery for 2001. The Moomba 136 well which is in the Cooper/Eromanga Basins tested at 3,845 b/d. The company plans to bring the well onstream by the end of March 2001.*

Santos has reportedly found gas with the *Roti-2 exploration well in the Queensland section of the Cooper/Eromanga Basins. The well flowed gas at 6.7mn cf/d and 480 b/d of condensate.*

Phillips Petroleum has reportedly *decided to proceed with a second phase of development at Peng Lai in China's Bohai Bay after an appraisal well tested at 425 b/d of 21° heavy crude in 75 ft of water. The second phase will also involve several wellhead platforms and a processing platform. Production of 60,000 b/d is slated for 2005.*

Latin America

Petrobras's P-36 Roncador semisub- *mersible has sunk, following two explosions and a fire in the early hours of 15 March 2001. A total of 10 personnel have been confirmed dead, and one seriously injured. The remaining workers were evacuated as firefighters tackled the fire before it sank. The platform came onstream last summer, and was producing 80,000 b/d of oil.*

Suriname has reportedly announced *that it intends to hold its first licensing round this year. Seven licences will be on offer, six near-shore and one offshore block. The company has 22 blocks in total to offer, to be licensed in a phased process over the next five years.*

Africa

Repsol YPF and partners TotalFinaElf, *OMV and Saga have made a second oil discovery with the B-1 well in exploration block NC-186 in the Murzuq Basin in the Sahara Desert in Libya. The well flowed at 1,300 b/d of oil and is located just 40 km from the existing El-Sharara facilities which have spare capacity.*

Sonatrach, the Algerian state oil com- *pany, has signed a deal estimated to be worth $2bn with Gaz de France and Petronas of Malaysia, for the exploration and development of a southern gas field in the Ahnet region, writes* Stella Zenkovich.

In Brief

Amec has secured the contract to *build and install the topside modules on the Bonga floating production vessel destined for the deepwaters offshore Nigeria. The vessel, which will process 225,000 b/d of oil, is currently under construction at Samsung's South Korea yard.*

Gambela Petroleum, a subsidiary of *Pinewood Resources, based in North Vancouver, has signed a production sharing agreement with Ethiopia and is now looking for an equity partner for its 15,000 sq km concession in the southern part of the country, reports* Stella Zenkovich.

Algerian state oil company, Sonatrach, *has discovered an oil field at a depth of 3,700 metres located in the Qued Mya Basin in Algeria, according to* Stella Zenkovich.

Angola's annual average production is *to be increased by 23.6% in 2003 to 914,755 b/d from 2000 following state oil company Sonangol's development of new offshore oil fields, notably Kuito, Girassol, Dalia, Hungo and Chacalho, writes* Stella Zenkovich.

Lundin Oil's Thar Jath discovery well *on block 5A onshore Sudan is reported to have tested at 4,260 b/d of oil.*

TotalFinaElf has begun production on *the Atora oil field, located onshore in the Gabonese equatorial forest, 35 km north of Gabon which is in the Ogooué Maritime Province. Production is expected to soon plateau at 20,000 b/d.*

Foster Wheeler Energy Ltd (FWEL) *has been awarded a contract to carry out the basic design and engineering package for Sasol Petroleum Temane's Temane Pande development project. Sasol plans to convert its Sasolburg plant in South Africa to natural gas feedstock, transported via an 895-km pipeline from the Temane and Pande gas fields onshore Mozambique.*

Energy Africa, together with co-ven- *turer Taurus Oil of Sweden, has gained three further exploration permits covering the Tiznit offshore area offshore Morocco. A 3D seismic programme is slated to begin in mid-2001.*

In Brief

NEWS Industry

UK

***Enterprise Oil has posted what it states** is a record turnover of £1,841.2mn and post-tax profit of £529mn (excluding special items) for 2000. It also reports production growth of 31% from 1999 at an average 280,563 boe/d – the group's highest level to date. Four new fields came onstream in the year – Cook, Bell, Bittern and Sygna, all in the North Sea.*

***Ray Hunter, the Scottish Windfarm** Development Manager with Renewable Energy Systems (RES), speaking at the All-Energy Futures Conference in Aberdeen, believes Scotland has the potential to become a significant world force in the manufacture of offshore renewable-energy equipment. He stated that Scotland's eight windfarms have a combined rating of just over 100 MW and forecast that for the next decade 100 MW will be the average annual rate of installation.*

***BetzDearborn and Brocol have entered** into an alliance to provide customers in the UK with a complete package of products and services for compliance with legislative requiremens for the control of Legionella bacteria.*

Europe

***As part of a strategy to reduce its capital** invested in shipping activities, Vopak has sold one-third of its 30% stake in Dutch company Heavy Transport Group to its partner Heerema.*

***The European Commission has given** German company Michel Mineralölhandel the go-ahead to purchase Thyssen-Elf Oil's sales agencies in Essen and Stuttgart, after which the company will cease trading.*

***South African fuel group Sasol has** acquired Condea, the chemical branch of the German energy group RWE-DEA, reports* Keith Nuthall. *The deal includes assets in Germany, shares in operating companies in Italy and the Netherlands, and subsidiaries in France, Spain and Belgium.*

***The Repsol YPF Board of Directors has** proposed a gross overall dividend for 2000 of euro 0.5 per share – this is equivalent to 25.1% of the company's net income for 2000.*

Travel and deep venous thrombosis – IP update

There is growing concern and interest among air travellers, particularly long haul, about the risk of developing deep venous thrombosis (DVT) and subsequent pulmonary embolism, writes *Dr Lucy Wright*, Chair, Occupational and Environmental Medical Committee, Institute of Petroleum.

The phrase 'Economy Class Syndrome' has been applied to cases of air travellers who have developed DVT. This phrase, however, is misleading since it implies a direct causation between economy class of travel and DVT and deflects attention from the known fact that any individual who has been seated or immobile for prolonged periods, in for example a theatre or a vehicle, may also be at similar risk. Further to this, cases of DVT have been associated with Business, First Class and Concorde air travel in addition to Economy.

Whilst the research which has been reported identifies recent air travel as a common factor in DVT cases, it does not provide conclusive evidence that it is flying that is the specific risk. It does however indicate that, whilst the dehydration that can occur in an aircraft environment may in some way contribute to the risk of developing a DVT, it is the immobility and/or possible constriction of the lower limbs which is an important factor.

DVT's occur in any population and, in addition to immobility, several conditions have been identified which increase an individual's susceptibility to, and risk of, DVT. These include:-

- previous or family history of DVT;
- malignancy;
- hormone treatment;
- recent surgery;
- abnormalities of blood clotting factors, and
- trauma involving the lower limbs.

The risk of DVT can be reduced and the following advice will help air and other travellers, likely to be constrained in their movements for prolonged periods, avoid its development:

- drink adequate fluids to avoid dehydration;
- avoid smoking;
- avoid alcohol;
- avoid crossing legs when seated;
- walk around within the cabin area whenever you can;
- stand up in your seat area and stretch your arms and legs;
- carry out foot and leg exercises (several airlines, notably British Airways, have a Well-Being Section in their in-flight magazines);
- wear loose fitting comfortable clothes when travelling;
- avoid tight socks that constrict the lower leg/calf;
- seek medical advice before travelling if concerned about any DVT or risk factors; and
- consider using support stockings.

Although the mechanism of any effect is unclear, there is a view that the use of a small dose of Aspirin prior to flying may help reduce the risk. It should, however, be borne in mind that Aspirin itself is not without its own risks and side effects.

Individual employees can seek further advice from their company occupational health departments.

North America

***Conoco has announced a $1bn stock** buyback programme over a three-year period. At current stock prices, approximately 5.7% of the company's 624mn shares outstanding could be repurchased. The new programme replaces the existing stock buyback programme intended solely to offset the dilution associated with employee compensation plans.*

***Shell Oil Company is proposing to** acquire the US company Barrett Resources for $55 per share. The offer represents an aggregate purchase price of approximately $1.8bn plus the assumption of Barrett's $400mn debt. If successful, the deal will give Shell an immediate material presence in the Rocky Mountain region, the second largest natural gas basin in the US.*

***Carpatsky Petroleum has signed a** binding Letter of Agreement to acquire Lateral Vector Resources, an independent oil and gas company based in Regina, Saskatchewan, in a stock-for-stock transaction.*

NEWS Industry

WEC focuses on energy pricing

The World Energy Council (WEC) recently published its 2001 Statement on 'Pricing Energy in Developing Countries.' Commenting on its publication, WEC Chairman Jim Adam stated that the issue of energy pricing was 'an especially important topic for developing countries right now' and that 'the fundamental need to work toward the right balance between the benefits of market pricing for energy and social or other national goals cannot be overemphasised.'

The Statement identifies basic principles focused on helping improve energy pricing and subsidisation in developing countries. It stresses:

- The urgency of implementing full cost recovery principles and adequate cost-of-service determination as a prerequisite to accurate pricing.
- The usefulness of marginal cost pricing and opportunity cost pricing in the global optimisation of resources.
- The need to enforce adequate metering, billing and collection in order to secure financial viability for energy providers and fairness for payers.
- The need to provide targeted subsidy schemes to ensure minimal energy service to the poor.

Wind energy – the next major offshore industry?

Wind energy is set to be the major new offshore industry of the next generation, according to the recently appointed Executive Vice President of Shell Renewables' Wind Energy business David Jones, speaking at a conference in Aberdeen. The potential for renewable energy is enormous and he predicted that, in time, with improvements in technology and the need for sustainable development, renewables could emulate the rise of oil 100 years ago when it overtook coal and wood as the primary fuel source.

Wind energy could be at the forefront of that development. 'Wind is the most competitive of the renewable energy sources when comparing costs with conventional fuels,' said Jones. 'Wind energy production is expected to increase rapidly as it moves offshore to achieve wind farms of greater scale.'

Shell plans to be a 'major player in the global wind energy sector.' The company's interest spans all aspects of the development chain – identification, site evaluation, design, construction and operation. It was involved in the construction and operation of the UK's first offshore wind farm at Blyth, which comprises two 2 MW turbines capable of generating enough power to meet the demands of 3,000 'average' UK households. Two wind turbines have also been erected at the Shell refinery in Harburg, Germany. Each can produce 1.5 MW of power and together can supply more than 2,300 homes. The 'green' electricity is sold to residents of Hamburg through a Shell and NEU Power marketing initiative.

The company also recently announced its partnership with Nuon, the ING bank and Jacobs Comprino in a consortium called Noordzeewind for the large-scale production of offshore wind power in the Netherlands. The consortium is to participate in the invitation for tenders with the Dutch Ministry of Economic Affairs is expected to issue soon for the 'Near Shore' 100 MW wind park off the Dutch coast at Egmond.

Russia & Central Asia

The Croatian Government and Croatian *Ministry of the Economy have appointed PriceWaterhouseCoopers and Deutsche Bank to jointly advise them on the reform of the Croatian oil and gas market and the restructuring of the state owned company Industrija Nafte DD Zagreb (INA).*

Sibneft, reports UFG, expects to beat *its previous production forecast by 3.5% and to increase output to 20mn tonnes in 2001, up 16% from 2000. This would make it the fastest growing oil company in 2001 as Yukos recently lowered its growth targets to 15%.*

Lukoil has announced plans to restruc*ture its subsidiaries, reducing the number of existing subsidiaries and establishing new ones in the company's main operating areas of Western Siberia, Komi, Timan-Pechora, Lower Volga, Perm and abroad, according to UFG. These plans are irrespective of original ownership, core subsidiaries incorporated during privatisation, joint ventures and newly acquired assets.*

In Brief

Ukrainian Deputy Prime Minister *Yulia Timoshenko has been charged with corruption, smuggling as well as embezzlement, reports Stella Zenkovich. Popularly referred to as 'Queen of Gas', Timoshenko has been forced to resign and follow her husband into jail. Oleh Dubina, Director of the Krivorizhstal plant, has been nominated at Deputy Prime Minister in her place.*

Yukos, according to UFG, has bought *the Russian assets of Eurogas, a Toronto-listed independent, for a total of $16mn. Yukos will gain a 50% interest in a 1bn boe non-producing gas condensate field in the Yamal-Nenets district through this deal.*

Devon Energy, the US independent, *has acquired a 0.8% in the Azerbaijan International Operating Company (AIOC) from Ramco Energy for $58.3mn, according to UFG.*

Lukoil has announced its production *and financial targets for 2001, according to UFG. The company plans to produce 79mn tonnes of oil (1.58mn b/d), approximately 2% higher than in 2000 and the company expects a $2.6bn pre-tax profit.*

Asia-Pacific

Fletcher Challenge shareholders are *reported to have agreed to sell the company's New Zealand energy division to Shell and Apache for NX$4.9bn ($2.1bn) in cash and shares.*

BHP is reported to have put in a *counter-bid to Shell's offer for Woodside Petroleum of Australia.*

China, according to UFG, is looking to *convert oil-fired power plants to gas in order to reduce the country's reliance on crude oil. The government plans to boost consumption from 24bn cmly in 2000 to 80bn cmly in 2010. The main driver for this move, it is suggested, is the recent discovery of 700bn cm gas field in northern China.*

CNOOC has reportedly raised *$1.26bn by selling a 20% stake in an initial public stock offering that drew a substantial response from institutional and retail investors. The sale follows the company's failure in 1999 to raise $2.5bn via a stock sale to overseas investors. A subsidiary of Shell was among those that bought a stake.*

In Brief

UK

Innogy Holdings is planning to buy Yorkshire Power Group.

Ofgem, the UK gas and electricity industry watchdog, intends to remove the last of its price controls on British Gas now that competition in the market has reached a 'sufficient' level.

Simon Storage is planning to build a new bulk liquid terminal at Grangemouth Docks in Scotland.

Europe

The European Commission has further signalled that it is unlikely to accept future national aid schemes that seek to compensate businesses because of rises in fuel costs, writes Keith Nuthall.

Oiltanking has agreed in principle with Odfjell that the latter will acquire 50% of Oiltank Singapore Chemical Storage.

The European Union Council of Ministers has agreed in principle to extend for six years a series of derogations from EU rules on excise duty for a wide range of fuels, reports Keith Nuthall.

North America

SG Resources of Houston is to sell Houston Energy Center, its Texan greenfield natural gas salt cavern storage project, to Aquila for an undisclosed sum. The storage facility is slated to become operational in 2002 and, by 2004, will have reached 12 bn cf of leasable capacity.

A project called the Millennium Pipeline, which is costing an estimated $640mn, is expected to be approved soon by the US Federal Energy Regulatory Commission, reports Monica Dobie. *The project will move gas from the Canadian Rockies into densely populated regions on the East Coast of the US through a pipeline to be built under Lake Erie, across the province of Ontario into New York State. It is hoped that the pipeline, measuring 341 mm in diameter, will be in operation by November 2002.*

Lukoil, according to UFG, is planning on acquiring a 150,000 b/d refinery on the East Coast of the US and a network of petrol stations in Canada. The Russian company already owns 1,300

Green measures in 2001 UK budget

The UK Chancellor Gordon Brown announced a 2 p/l duty cut on ultra-low sulfur petrol (matched by a cut in duty on unleaded petrol until 14 June 2001 to guard against any disruption to the wholesale and retail markets in the final stages of transition to ULSP) and a 3 p/l duty cut on ultra-low sulfur diesel (ULSD) in his latest budget. He also abolished the duty premium on lead replacement petrol (LRP) and super-unleaded petrol so that it will in future have duty levied according to the sulfur and aromatics content.

As part of the government's Green Fuels Challenge to encourage the uptake of environmentally-friendly alternative fuels, the duty on road fuel gases is to be cut by the equivalent of 3 p/l and not increased in real terms until at least 2004. Budget 2002 will introduce a new duty rate for biodiesel set at 20 p/l below the ULSD duty rate. Brown also stated that the government is to support a number of pilot projects for hydrogen, methanol, bioethanol and biogas through special duty reductions or exemptions.

He also placed a freeze on all car and motorcycle vehicle excise duty (VED) rates and extended the small car threshold for VED for existing cars to 1,549cc, including some Ford Escorts, Vauxhall Astras, Nissan Micras and Rover Metros. Also unveiled was a major reform of lorry VED claiming to reduce UK rates to among the lowest in Europe for the cleanest lorries.

The Budget 2001 also introduces a number of measures proposed in the pre-budget report, plus additional ones to help deliver the government's environmental strategy. The climate change levy package comes into effect on 1 April 2001, aimed at encouraging energy efficiency and the use of renewables and 'good quality combined heat and power (CHP),' to reduce carbon emissions by at least 5mn t/y by 2010. Every penny of levy revenues are to be recycled through a 0.3 percentage point reduction in employers' national insurance contributions and a package of support for energy efficiency.

The government is also investing £100mn over three years in a new Carbon Trust – which will provide free energy efficiency advice to businesses and promote low carbon technologies. Some £50mn of climate change levy revenues over three years will also be invested in developing renewable technologies.

It was also announced that firms will benefit from 100% capital allowances on a range of energy saving technologies. The new Energy Technology List will be published by 1 April 2001 and will be available at **www.eca.gov.uk** Firms will be able to further reduce their climate change levy liability by using 'levy-free' new renewables and CHP energy sources.

Brown also revealed that the government will consult during the summer on a Green Technology Challenge to make further use of accelerated first-year capital allowances to encourage the development of environmentally-friendly technologies.

Egyptian gas deal

Shell recently finalised a Concession Agreement with the Egyptian General Petroleum Corporation (EGPC) to allow the Fayum Gas Company, a Shell Gas subsidiary, to deliver natural gas to the Fayum Governorate in Egypt.

The agreement gives the Fayum Gas Company a 20-year franchise to study, design, finance, build and operate a natural gas transmission pipeline and distribution network, and to market natural gas to industrial and residential customers, on behalf of EGPC.

The agreement follows the recent announcement by Shell that it is acquiring a minority stake in the NatGas concession that includes areas bordering on Fayum Governorate.

Technological alliance

BP and France's IFP have formed an alliance to develop and commercialise BP's OATS gasoline desulfurisation technology. The OATS process is a step-out method for the removal of sulfur from fluid catalytic cracked (FCC) gasoline and is claimed to reduce sulfur levels to below 10 ppm with very limited reduction in octane rating and limited hydrogen consumption, while improving the Reid vapour pressure (RVP) characteristics of the gasoline fraction.

IFP will take over further development of OATS, carry out pilot testing and will act as the exclusive licensor for the technology. The first commercial units are expected to be fully operational before 2003.

NEWS Downstream

Robust growth in W. Europe fuel retailing

Forecourt retailing in Western Europe is set for a period of robust growth according to Datamonitor's new report *Convenience Retailing on the European Forecourt.* The report states that due to increasingly busy and fragmented consumer lifestyles, traditional shopping habits will disappear and people will instead use convenience food retailing. Over the next five years, oil companies will be the main beneficiaries of this shift in consumption patterns as service stations are ideally suited to cater for this changing consumer lifestyle. The main findings of the survey are:

- Western Europe's forecourt network will increase by 11% by 2001. Italy and Spain will lead this trend with growth rates of 50–80%.
- Non-fuel revenues, driven primarily by food sales, will grow by 60% by 2005.
- Added-value services will transform the European forecourt shop into a 'community-hub' by 2010.

UK Save Group made insolvent

Save, Britain's biggest independent petrol retailer, has called in the administrators, blaming the banks, not the petrol price war.

James Frost, former Chairman of Save, who immediately resigned his position, accused his bankers – a syndicate led by Barclays that also included Lloyds TSB and NatWest – of providing 'drip, drip, drip' financing combined with exorbitant charges. Save owes £50mn to the banks but owns £200mn of real estate assets so the banks should receive all the money owed.

Court ruling on German energy subsidies

The European Court of Justice has ruled that Germany's law on subsidising power derived from renewable energies is in line with European Union law. The ruling is reported to secure renewable energy producers generous prices set by the state, but payable to utilities and their customers.

The Court ruled that mandatory minimum charges payable by power distributors for green power did not represent state aid. The Court also said that the protection of the environment was one of the EU's paramount goals in order to meet its international obligations to reduce greenhouse gas emissions and implied that national renewable energy sources could be favoured over alternative import offers even if certain free trade principles were being violated.

UK Deliveries into Consumption (tonnes)

Products	†Jan 2000	*Jan 2001	% Change
Naphtha/LDF	238,390	205,050	–14
ATF – Kerosene	736,517	759,181	3
Petrol	1,684,960	1,823,268	8
of which unleaded	1,541,502	1,292,264	–16
of which Super unleaded	41,167	106,044	158
of which Premium unleaded	1,500,335	1,186,220	–21
Lead Replacement Petrol (LRP)	143,458	91,429	–36
Burning Oil	405,622	493,821	22
Automotive Diesel	1,177,645	1,293,237	9.8
GasOil/Marine Diesel Oil	641,631	589,848	–8
Fuel Oil	166,357	208,878	26
Lubricating Oil	64,147	71,096	11
Other Products	611,044	653,668	7
Total above	5,726,313	6,098,047	6
Refinery Consumption	460,764	401,996	–13
Total all products	6,187,077	6,500,043	5

† Revised with adjustments * Figures dated from Feb 2000 onwards are the final figures as supplied by reporting companies.

In Brief

forecourts in the US, supplying them with 300,000 b/d of crude supplies from Timan-Pechora.

Middle East

***Armenia and Iran are making final** preparations to start the construction of a $120mn gas pipeline which will pave the way for eventual Iranian gas exports to Europe, writes* Stella Zenkovich.

***BP, the National Iranian Oil Company** and India's Reliance Group have reportedly signed a Memorandum of Understanding for a feasibility study looking at the possibility of building an 8mn tonne LNG plant in Iran.*

Russia and Central Asia

***Lukoil is planning to acquire a control**ling stake in Ventspils Nafta, one of the key transhipment terminals for Russian crude and refined oil products, reports UFG.*

***Hungarian oil and gas company Mol** has put in a bid to acquire a stake in Poland's 4.5mn t/y Gdansk oil refinery. The refinery also operates a retail network of 20 owned and 245 franchised stations under its brand name.*

***Gastroymontaj, a Bulgarian private** contractor for gas transmission facilities, has completed an expansion of the country's gas transit network to increase deliveries of Russian gas to Turkey to 36–39mn cm/d.*

***BP, according to UFG, plans to begin** purchasing crude from Sidanco in order to process it at the Moscow refinery to supply its Russian retail network.*

Asia-Pacific

***Conoco and Malaysian state oil com**pany Petronas have signed a Memorandum of Understanding to acquire Statoil's 15% stake in the joint venture Melaka refinery in Malaysia. Conoco currently holds a 40% interest in the 100,000 b/d refinery. Petronas operates the facility and currently holds a 45% stake.*

Africa

***Sonangol, reports* Stella Zenkovich, *is** to build a new refinery in Lobito, in the coastal Benguela province.*

Black hole or black gold?

There may have been remarkable changes in the Russian oil and gas landscape over the past two years. High oil prices have helped. But the industry itself has become more efficient, it is subject to a much more stable and predictable tax regime, operates in an environment where domestic oil prices provide an acceptable return, and is now investing in growing production for the future. *Stephen O'Sullivan* and *Dmitry Avdeev* of United Financial Group in Moscow report.

The Russian oil industry is set to have another good year in 2001 despite the expected decline in world oil prices. The economic situation continues to be favourable, although uncertainty over the sovereign debt repayment schedule does pose some threat of unpredictable tax increases. Production is rising, although we expect the rate of increase to slow. The final convergence of domestic oil netbacks with export ones reduces the negative impact of the likely decline in international markets. Costs remain under pressure from inflation, although the industry is now better at controlling costs than before the oil price shock in 1998.

In the gas industry, however, liberalisation of the domestic gas market is a pre-requisite for the stable and commercially sound development of the sector.

Economic outlook

The economic outlook remains relatively benign for the industry. A 4% GDP growth (against 7.7% in 2000) will boost domestic energy demand, ensure political and economic stability and contribute to the continuing improvement in the overall investment climate.

The fiscal situation is cause for a little more concern since Russia is likely to be forced to service its Paris Club debt in full ($2.4bn in addition to the already budgeted expenditure) and will be able to raise $3.7bn less in external financing. A financing gap of $6.1bn has therefore emerged.

As a result, the oil sector is likely to be dangerously exposed to changes in taxation, particularly in the event of a sharp deterioration in the external environment – although this looks rather unlikely, with most risks on the upside.

$ mn	1997	1998	1999	10mo00*	2000F**
Exploration drilling	618	328	192	281	337
Operating drilling	1,637	712	410	798	960
Equipment	1,214	598	548	1,157	1,392
Industrial construction	2,420	1,201	786	1,177	1,416
Non-production capex	448	137	71	106	127
Total capex	**6,338**	**2,976**	**2,007**	**3,520**	**4,233**

** First 10 months of 2000. ** Forecast*
Source: Neftegazovaya Vertical, UFG Research

Table 1: Oil industry capital expenditure

$/b	1Q2001	2Q2001	3Q2001	4Q2001	2001	2002
Brent	27.15	24.20	21.57	19.23	23	18.50
Urals – Mediterranean	23.60	22.07	20.74	19.43	21.46	17.20
Domestic crude	16.79	16.03	15.27	14.51	15.65	14
Gasoil – export	229	214	201	189	208	168
Fuel oil – export	122	122	116	110	117	99
Gasoline – domestic	345	334	322	311	328	302
Gasoil – domestic	261	261	253	241	254	221
Fuel oil – domestic	109	109	107	101	107	95

Source: UFG Research

Table 2: Oil price forecasts

Oil production

Production is finally on an uptrend. After the 5% increase in 1999, 2000 saw production rise by 6%. After years of relentless decline, the more benign operating environment in the post-1998 world (higher prices, reduced costs because of devaluation and a supportive tax environment) has enabled the decline to be stemmed and even reversed. We at UFG expect 2001 growth to be slower than in 2000, since the investment that has been made in recent years focused on the quick wins – areas where production can be increased with the least amount of effort. Once those sources of production growth have been exhausted, investment will need to focus on areas where the returns are not quite so good, albeit still positive.

The production decline in Russia was caused by a number of factors. The main one was that rehabilitation and well workovers were simply not being undertaken in the pre-1998 price and cost environment (see **Table 1**). A 30% decline in both the number of metres drilled and the number of exploration and development wells drilled was recorded in 1998. In 1999, drilling volumes were up by 7%, although the number of wells drilled remained the same. We expect to have seen at least a 50% increase in drilling volumes in 2000 and a 30–40% increase in 2001.

Our estimate of profitability suggests that the industry's operating cashflow was $21bn in 2000 and will be $15bn in 2001, even with the lower oil prices that we expect. Since estimates of the capital expenditure needed to increase production range from $5bn to $7bn a year, it seems clear that the industry will have sufficient funds to make the necessary capital expenditure, at least this year if not well into the future since even with mid-cycle prices of $18.50/b the industry should make $11bn a year in operating cashflow.

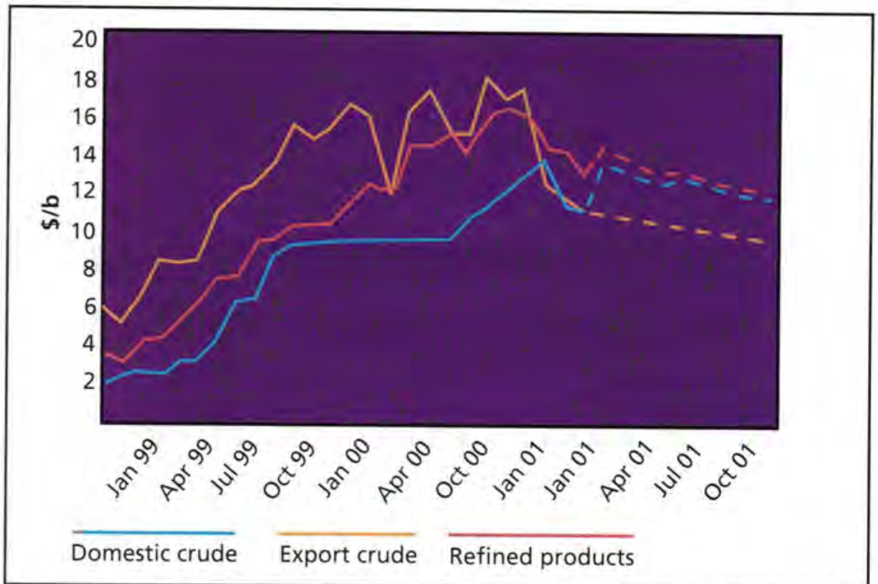


Figure 1: Crude netbacks *Source: UFG Research*

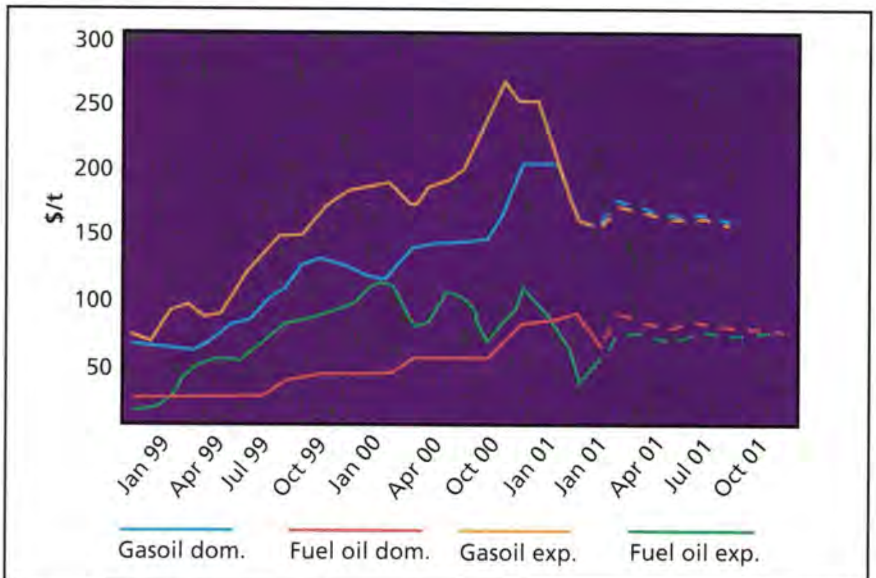


Figure 2: Refined product netbacks *Source: UFG Research*

Gas production

Gas production is a contentious issue. In 2000 it declined by 23bn cm, amidst allegations that assets and contracts had been transferred from Gazprom to Itera (whose production rose by a similar amount). Gazprom claims that it plans to increase production by 7bn cm (1.3%) this year in order to ensure that the company can meet both its domestic and export commitments.

As the declining supply trend becomes more obvious – even to the government – the pressure for tariff reform will steadily increase. However gas tariff reform is likely to be a tougher nut to crack than it might at first sight appear due to fears over inflation. Nevertheless, it is an essential prerequisite if it is ever to become attractive for Gazprom to invest in reserves designed to serve the domestic market.

Prices

We have based our analysis in **Table 2** on a $23/b Brent price forecast in 2001 and historical correlations between international and domestic crude and refined product prices.

We have assumed that the differential between Brent and the Urals Mediterranean will increase from the historic level of $1/b to $1.50/b in the future. The wider discount reflects the falling demand for higher sulfur crudes in Europe and the increased supply in this market segment.

One of the key trends that has been evident over the past year or so has been the convergence between the domestic price and the export price. The netback (the price the seller receives after all costs and taxes have been deducted) has now become the same whether the crude is exported or refined domestically. See **Figure 1**.

As a result, we believe that the domestic crude price will remain relatively firm despite the significant decline in international crude prices since we expect it to be supported by the convergence between domestic and international refined product prices. This convergence has accelerated in the past couple of months after the government lifted most of the export restrictions on refined products

Tonne/employee	1997	1998	1999	2000F*	2001F*
Lukoil	577	578	516	566	584
Surgut	494	508	536	490	512
Sibneft	454	577	605	614	678
Yukos	n/a	374	454	551	633

** Forecast*
Source: Company reports, UFG Research

Table 3: Output per employee

	1997	1998	1999	2000
Electricity tariffs, $/MWh	36.69	22.58	10.24	12
Transneft tariffs, $/t	18.33	14.91	14.49	18.28
Crude freight, $/t	n/a	3.97	4.17	8.91
Average salary, $/month	338	184	142	240

Source: UFG Research

Table 4: External cost factors

allowing traders to arbitrage the pricing gap. See **Figure 2**.

Collection rates

Low collection rates were once the bane of a Russian company's life. Payments were late or never made at all while barter represented a huge proportion of transactions that did take place. Companies like Gazprom had entire departments devoted to the handling of barter transactions, so much so that the Russian economy was famously described as 'a virtual economy.'

One of the positive benefits of the 1998 financial crisis was the remonetisation of the economy and the greater volume of cash circulating. In 1999 the oil industry took a major step forward when higher international oil product prices made it attractive for Russian refiners to export large volumes to European markets. The resulting shortages forced domestic prices higher and enabled oil companies not only to improve their domestic refining margins but also to target their sales at solvent customers. In 2000, the same occurred and the oil industry has generally moved to a cash payment basis with barter virtually eliminated from the sector.

Collection rates and non-payment are issues therefore really only relevant now to the gas sector, where it continues to be something of a problem – although much reduced from previous years. Gazprom now collects 95% of its receivables, although only 75% of these are in cash.

Costs

One of the advantages that the Russian economy gained from the 1998 financial crisis was relief from an overvalued exchange rate. This cost advantage has been eroded by inflation in the economy. However, every cloud has a silver lining and one of the positive changes caused by low oil prices was the pressure to cut costs and improve performance.

The financial crisis in 1998 initially took the pressure off the industry as margins widened while rising oil prices in 1999 cemented the recovery. Nevertheless, many companies have acknowledged that their cost structures were inappropriate for the oil industry in the 1990s and set about changing them. Early retirement schemes, the spin-offs of non-core assets and direct layoffs combined with the increase in production have increased average employee productivity (see **Table 3**).

However as the industry continues to optimise its internal structure, external factors, such as the tariffs of natural monopolies and rising labour costs, represent an increasingly large share of their expenses. That said, many of these factors are themselves very sensitive to oil prices – 30% of electricity is generated from fuel oil and Transneft is only allowed to impose high tariffs when oil companies have excess profits and the cost of crude oil freight is highly correlated with the level of the oil price. (See **Table 4**.)

Export capacity

Exports have long been an important source of revenue for Russia and they are likely to remain so. Export netbacks for crude have been above those for domestic sales for a considerable time, only falling beneath the latter in January 2001 when export prices fell sharply. It is export capacity not the level of attractiveness that has been the real constraint on exports in the past.

Export capacity is, however, finally being expanded. There is a new 300,000 b/d pipeline currently being constructed to the Russian Baltic coast, called the Baltic Pipeline System. Lukoil is building the 140,000 b/d Varandey terminal on Russia's northern coast.

Completion of the 600,000 b/d Caspian Pipeline Consortium project to Novorossiysk will also free up capacity in the Transneft system that is currently used to transport Kazakh crude.

The Blue Stream pipeline under the Black Sea to Turkey will be completed this year and initial deliveries will commence shortly thereafter. Ultimately this will build to 16bn cm/y and will be Gazprom's second largest export market after Germany.

Oil industry restructuring

The formation of the Russian oil sector is almost complete by now both in terms of ownership and market development. As a result we expect only minor structural changes.

The state retains control over only two major oil assets, Slavneft and Rosneft, although the government does not seem to be willing to sell controlling stakes in these companies in the near future – due to political issues in the case of Slavneft and the necessity to maintain the state's presence in production sharing agreement (PSA) projects through Rosneft.

That said, more serious than expected fiscal problems (caused by a fall in commodity prices or by the failure of other planned asset sales) may force the government to reconsider its privatisation plans. The authorities have already announced that they would sell a 20% stake in Slavneft if the Level 3 ADR offering of 6% in Lukoil fails. While such a sale would not be attractive to portfolio investors due to corporate governance concerns, TNK, which already owns a 12% stake in the company and significant stakes in its subsidiaries, has expressed its intention to bid for Slavneft.

Among less important privatisations, the 360,000 b/d Norsi refinery in central Russia has been scheduled for sale in 1H2001 with downstream-short Lukoil being the only potential acquirer of the plant.

Following a series of privatisations and acquisitions four major private-sector oil players have emerged – Lukoil, Yukos, Surgut and TNK (including assets under the control of its principal shareholders) – which will remain the focus of the future consolidation in the CIS oil and gas industry. Sibneft still has a chance to move up into the premier league, although its failure to acquire Onaco last year has raised concerns about its long-term prospects of staying independent.

Tatneft and Bashneft are out of play

Segment	2000–2002	2003–2007	2007–2009
Production	Incorporation of 6–8 production subsidiaries, separate accounting and self-financing. Limited presence of independent producers.	Competition between production subsidiaries and independent producers.	Further independence of production subsidiaries.
Transport	Incorporation of some transport assets into fully-owned subsidiaries, separate accounting.	Complete incorporation of transport assets, fully transparent tariff system.	No change.
Non-FSU exports	Gazprom monopoly, no access for independent producers, production subsidiaries do not directly benefit.	Gazprom monopoly on sales, independent producers and production subsidiaries retain economic benefits.	Direct access for production subsidiaries and independent producers.
FSU exports	Limited access for independent producers.	Direct access for independent producers and production subsidiaries.	No change.
Domestic gas market	Non-discriminating access for independent producers, production subsidiaries to sell through Gazprom.	Competition between independent producers and production subsidiaries, limited price regulation.	Competition from FSU producers, spot gas market, less price regulation.

Source: The Concept, UFG Research

Table 5: Gas market deregulation sequence

due to their quasi-national status and for the same reason they are unlikely to be acquiring significant assets outside their core regions.

Sidanco remains something of a wild card. We expect an agreement to be reached between TNK and BP over the return of the Chernogorneft assets to Sidanco and the acquisition of a 25%+1 blocking minority stake in Sidanco by TNK. It is likely that when the deal is closed, BP will sell its stake. If that happens, one likely outcome is that TNK and Sidanco would merge.

We expect foreign involvement to grow very gradually focusing primarily on offshore PSA projects (Sakhalin, Arctic shelf, northern Timan-Pechora), which do not rely on Transneft's export infrastructure. Onshore PSAs will not be successful because of transport problems.

Gas sector restructuring

The high level of gas market regulation, low tariffs and restrictions on foreign ownership are the key structural issues facing the Russian gas industry. We believe that the limit on foreign ownership in Gazprom is likely to be lifted in 2001, providing the company with access to capital markets. Domestic gas market liberalisation is, however, a longer-term issue.

A blueprint of the gas industry restructuring plan, which was prepared by the Russian Ministry of Economic Development, proposes separating the competitive segments of the industry from the monopolistic segments by deregulating the industry in three stages (see **Table 5**).

Oil companies (provided that the Sibur monopoly on gas processing is eliminated) and Gazprom will be the main beneficiaries of the programme. Oil companies will benefit for obvious reasons – for example, Surgut's gas production currently constitutes 20% of its hydrocarbon output, but less than 1% of revenues. Gazprom will benefit indirectly as increased competitiveness of the domestic gas market will loosen the regulatory pressure on tariffs. (See **Table 6**).

The programme suggests that at the third stage of the deregulation process, domestic gas prices will equal or exceed export netback prices. We believe this is a realistic assumption based on the history of domestic oil prices, which now have reached between 85% and 100% of export netback level. The programme suggests that gas prices will reach \$31–\$50/mn cm by 2005.

mn cm	2000F*
Oil companies	30,422
Itera-related parties	19,642
Isolated local producers (Norilskgazprom, Tomskgazprom, Yakutgazprom)	7,460
Other	2,213
Total	**59,737**

** Forecast*
Source: UFG Research

Table 6: Largest non-Gazprom gas producers in Russia

The final word

There have been remarkable changes in the Russian oil and gas landscape over the past two years. High oil prices have of course helped. But the industry itself has become more efficient, is subject to a much more stable and predictable tax regime, operates in an environment where domestic oil prices provide an acceptable return and is now investing in growing production for the future. From black hole to black gold in under three years.

Sleeping giant awakes

The Kashagan oil field is claimed to be the biggest and most challenging development project of the next decade. *Christopher Pala* reports from Kazakhstan on the battle to secure operatorship of the field and looks at the challenges that lie ahead.

The rig drilling the Kashagan 1 discovery well surrounded by winter pack ice

When a consortium including four of the world's top five oil companies got together in late February to decide who would manage Kashagan, said to the biggest and most challenging development project of the next decade, one might have expected them to pick one of the giants and ignore the smaller four members. One would have been wrong. The Offshore Kazakhstan International Operating Company (OKIOC) consortium chose Agip – a unit of Eni, once Italy's dormant national oil company but now a newly aggressive player on the world scene… albeit still a middle-ranking one.

Named after a local poet, Kashagan is a giant structure under the shallows of the northern Caspian Sea, a reef of limestone lying three miles down and stretching for 50 miles. With an estimated capacity of between 10bn and 30bn barrels, it is thought capable of yielding peak production of 2mn b/d. Perhaps the fifth-largest oil field in the world and the biggest outside the Gulf, it is the most important discovery since Alaska's North Slope and the North Sea.

Little is publicly known about Kashagan. The Soviets spotted it in the 1970s, threw up their arms before the technical difficulties in producing it and focused instead on Siberia. But newly independent Kazakhstan, aware of the intervening technological progress and in dire need of monies to provide for its impoverished population, entered into a partnership with a half-dozen international oil companies to further explore the waters off its coast.

In 1997, OKIOC commissioned a seismic survey that revealed the structure in sharper detail. Although it has drilled only two wells so far, the first results indicate to geologists a thrilling resemblance with a smaller sister field – the richly endowed Tengiz field located onshore 100 miles to the east.

Battle for operatorship

As the data was coming in last year, the battle to oversee the spending of perhaps \$20bn in the next 15 years heated up. 'It's a once in a lifetime opportunity,' says Robert Ebel of the Center for Strategic and International Studies in Washington, DC. Operatorship brings no profits, but huge amounts of headaches and prestige.

OKIOC has an unusually large membership – five members with one-seventh each and four with smaller shares. Of the five, four campaigned for operatorship: ExxonMobil (the world's largest oil major), Shell (ranked second), TotalFinaElf (fourth) and Agip (which in the past year has doubled its output with the first two acquisitions in its 47-year history to reach sixth position, but is still one-quarter of ExxonMobil's size).

According to sources involved in the difficult negotiations over recent months, Exxon never stood a chance of securing the operatorship. 'We were a majority of European companies,' said one European executive, 'and we decided long ago we wanted a European operator. Besides, they [Exxon] would have spent too much money.' Since the oil is already going to be expensive to lift and to get to market, 'it was a factor' in the final selection, he said.

Julian Lee, Analyst at the Centre for Global Energy Studies in London, confirmed that ExxonMobil's average cost per barrel is 'toward the upper end of the range of the majors.' Ebel agreed.

Shell, too, drew little support. It had provided 80% of the expatriate staff in the first two years of the project and had been criticised for excessive delays and cost overruns.

TotalFinaElf forged ahead by buying BP's 9.52% share of OKIOC and Statoil's 4.76% for amounts that are still being fine-tuned. BP and Statoil were founding members of the consortium. They were initially joined in a partnership, which held a one-seventh (14.28%) stake in the consortium made up of two-thirds for BP and one-third for Statoil. This partnership dissolved with the two companies then holding individual shareholdings in OKIOC, which have now been sold to TotalFinaElf.

Unconfirmed estimates put the price of BP's stake at \$400mn and Statoil's at \$225mn. If these estimates are borne out, the two companies, which have spent roughly \$100mn and \$50mn respectively over the past seven years, will have made a tidy profit. The two purchases allowed the French company to rise above the crowd and increase its stake to 28.57% – less if the other stakeholders use their pre-emption rights, pro-rated on their existing share, to buy small slices of the BP and Statoil offerings.

Meanwhile, Agip campaigned with arguments that despite its relatively small size, it had gained valuable local experience as operator of Kazakhstan's large gas and condensate field at Karachaganak, north of the Caspian, and in the Blue Stream trans-Black Sea gas pipeline project.

In the end, Shell sided with the Italians rather than the French for reasons that remain unclear. At a crucial 9 February 2001 meeting in London, Agip was elected operator. ExxonMobil abstained and later put out a short statement saying: 'We are disappointed we were not selected. We believe we were best qualified to serve as operator.' The text made no reference to the winner and promised no support.

Battle far from over

But the battle is far from over, participants and analysts agree. Furious negotiations are underway to buy out whoever wants to sell and more consolidation is expected. 'At this point there are many buyers and few sellers,' said one of the buyers.

Several oil executives involved speculated that Agip may not operate Kashagan for more than two years, when the project will move from the appraisal to the peak-spending development phase. By then a partner may have bought its way to relative majority and thus taken the operatorship.

The key seller could be BG International whose 14.29% stake could clinch the operatorship for TotalFinaElf – or give Agip a chance of holding onto it, or even allow ExxonMobil or Shell to launch challenges. BG is one of Agip's partners in Karachaganak and may want to cut its risk in Kazakhstan, according to analysts. 'If somebody came to us and made us a good offer on Kashagan,' BG Chief Executive Frank Chapman told Reuters recently, he would consider it.

Another possibility would be that one of the big four buy BG in its entirety. BG's 14.29% share in Kashagan could then be obtained without being subject to pre-emption rights, as happened when Exxon bought Mobil, one of the original OKIOC stakeholders.

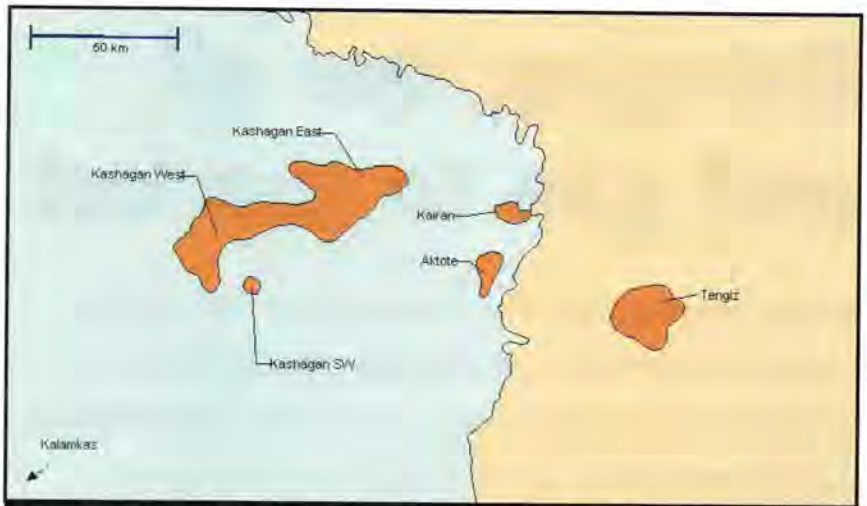
Were Philips Petroleum to sell the 7.14% it bought from the Kazakhstan Government in 1998 for $250mn, it could hope to get only $300mn or so – about as much as it has spent if one considers its share of OKIOC's expenses in the past three years, the sources said.

Inpex of Japan, which bought the other half of the one-seventh share that Kazakhstan sold after the 1998 financial collapse, is not considered a likely seller either – but that could change. 'Anything can happen,' said one insider.

Combination of challenges

In the meantime, Agip faces a field with a combination of challenges that are found together nowhere else – especially on such a huge scale. These challenges include water so shallow that it requires building an island for every platform; very high hydrogen sulfide (H_2S) levels; a sea that can rise several feet from storm surges and is covered with ice five months a year (see photo); with the whole thing located in a nature reserve that is a major breeding ground for fish.

Although the choice of an export route is not *per se* part of the operator's brief, Agip will undoubtedly be feeling the competing pressures of Russia, Iran, Turkey and Georgia, all vying to have pipelines go through their territory and all hoping for millions of dollars in transit fees and the promise of increased political leverage. In addition, OKIOC will have to contend with a government that has shown, at times, poor understanding of the oil business.



Map of north east Caspian showing onshore and offshore fields

President Nursultan Nazarbayev, who presided over Kazakhstan's independence from the Soviet Union, has maintained good relations with Moscow, built new ties with the US and earned Western respect for his handling of macro-economic policy. But in February, while the process to choose Kashagan's operator was underway, he made a statement that oilmen in Almaty say indicates he is receiving poor advice on oil.

Nazarbayev expressed impatience about the delay in choosing an operator and indicated that he believed that this was slowing down the project, something OKIOC officials emphatically denied. They said OKIOC has not been involved in the negotiations and has concentrated on its work, which in February meant mostly trying to get a 'fish' out of its second well. Nazarbayev, apparently seeking to influence the outcome of the vote, said the operator would have to meet five conditions:

- it must be financially sound;
- it must commit itself to producing commercial amounts of oil by 2005;
- it must neither flare nor re-inject the sour gas;
- it must co-operate with Kazakhoil, the state oil company, and
- it must not pollute the Caspian.

Several oilmen, speaking on condition of anonymity, said the government appeared to be under the impression that the operator would have more power and responsibility than is actually the case. For instance, its financial soundness – read size – is no more important than that of any of the other partners, because all are financing the project in proportion to their share.

When, on 9 February, the OKIOC shareholders met formally with Energy Minister and Deputy Prime Minister Vladimir Shkolnik to inform him of their choice for operator, Shkolnik, a former mining engineer, reportedly reiterated the President's demands, notably the 2005 deadline for commerical oil production. Kashagan oilmen say they are as anxious to recoup their huge investment as Nazarbayev is to boost his meager budget, but they stress that any commitment when so little is known about the field would be folly. Even if it were possible to start production by 2005, it may be more economical to do so a year or two later, they say. And in any case, Shkolnik was told, it was not up to the operator to commit to any date, but up to the shareholders who signed the production sharing agreement. But Shkolnik insisted and the announcement was delayed for two days while the two sides searched for a compromise. A few days after the announcement, an Agip official declared publicly that OKIOC would do its best to meet the President's deadline.

On another of Nazarbayev's conditions, the oilmen also say it may be in both Kazakhstan's and their interest to re-inject the high H_2S content gas into the field, instead of desulfurising it – the H_2S content is 15% – and selling it, probably for a very low price, to Russia's Gazprom, which has a gas pipeline not far from the Caspian's northern coast. Even then, re-injecting such sulfur-rich gas at a pressure of 850 bars will present a formidable technical challenge – just one more in the collection that the operator will have to grapple with in the next few years.

Bringing the oil and gas to market

No one would ever say that development of the Caspian's extensive oil and gas resources has proceeded – or is proceeding – smoothly. *John Roberts* reports on recent developments in the region.

Ever since Chevron first started negotiating with the Soviet Union in the late 1980s for development of the Caspian's Tengiz field, it has been a process in which visions of rapid field development accompanied by immediate and grandiose pipeline projects have been punctured by hard political and commercial realities.

In 2001, almost a decade after the three new Caspian states of Azerbaijan, Kazakhstan and Turkmenistan secured their independence, a more prosaic pattern is emerging. Oil field development is extensive, but the substantial investments in major projects are geared to more realistic timetables. We are still some years away from seeing the Caspian unleash its full potential.

The real thing

But there's a crucial difference between now and the early 1990s. It is not just plans or pipedreams, but financially-backed and commercially-targetted projects that are currently under way. And where there is doubt, such as over the long-mooted pipeline from Baku in Azerbaijan to the Turkish Mediterranean port of Çeyhan, it is because the balance is very, very delicate and the decision on actual construction so nail-bitingly close that past hopes and fears count as nothing. This is the real thing, with real money and real barrels of oil at stake.

The trick for all the Caspian producers is to marry production development with the establishment of new or expanded export systems. Kazakhstan's producers will shortly start to reap the benefits of the region's first major new large volume pipeline; but in Azerbaijan key issues concerning the intertwining of oil and gas field development and the pipelines needed to service those fields are just coming up for resolution. As for Turkmenistan, the inability of its leaders to pursue any kind of coherent strategy for energy development continues to ensure minimal availability of hard cash earned by actual oil or gas exports.

Kazakhstan projects

Kazakhstan has two major projects under way which are now proceeding, dully but effectively, on tramlines. These are the Tengizchevroil project at Tengiz and the Agip/BG/Texaco operation at Karachaganak. It also has the Tengiz–Novorossiysk oil pipeline, now being filled and thus ensuring a real increase in the country's severely constrained export capacity. And it has Kashagan (see p18), that most mysterious and problematic of oil developments, where the geological complexities are such that no one yet knows just when substantial production might start, just what recovery rates may be attained, or just how its output will reach the outside world.

At Tengiz, the operator, ChevronTexaco, is pursuing a step-by-step increase in production. Last year's output averaged 210,000 b/d and this year's will reach at least 240,000 b/d. A steady and sustained set of increases will carry output to 640,000 b/d by 2010. This plateau production level, announced by ChevronTexaco's Senior Caspian Executive Guy Hollingsworth in February 2001, is somewhat lower than previously anticipated levels of 700,000 b/d.

But, by then, Kashagan should be onstream. The field remains an enigma. A second well has just been drilled and until its results are disclosed the full extent of the field will not be clear. Industry sources believe it reasonable to suppose that reserves in place total as much as 40bn barrels, which would make it one of the world's largest fields. But Kashagan's complex geology makes it harder to assess the recoverable reserves. One barrel in five may be all that can be secured. Still, that does mean there would be 8bn barrels of oil available for lifting and that's a considerable prize.

Abiding concerns

Access to Russian export facilities remains an abiding concern of the Kazakh authorities. Both the Kazakh Government and the international oil companies in Kazakhstan, want to see a diversification of energy export routes. This is why ChevronTexaco is quite prepared to seek a place for oil from the Texaco development at North Buzachi in the proposed Baku–Çeyhan line. It is also the reason for intense Kazakh Government interest in southern oil export routes via Iran.

But these are medium-or long-term solutions. Right now, it is Russian routes that offer Kazakhstan the best immediate prospects. In late June, or thereabouts, first oil from Tengiz will reach the Russian Black sea terminal of Novorossiysk via the new 1,500-km pipeline developed by the Caspian Pipeline Consortium (CPC). The line will open with a capacity of around 32mn t/y, with 28mn t/y dedicated to carrying Kazakh oil and 4mn t/y to Russian oil. Such a capacity level – amounting to 560,000 b/d for Kazakh oil – is sufficient to meet immediate requirements.

CPC has no plans at present to implement the subsequent three stages of its project which are intended to take capacity up to 67mn tonnes (1.34mn b/d). This is largely because much of the expanded capacity would likely be dedicated to Russian exports, but Russia's oil industry is currently in a very uncertain state, and exports to a Black Sea terminal do not look particularly promising in an age in which environmental concerns about the capacity of the Turkish Straits to handle increased tanker traffic are growing steadily.

Eni holds a prominent position in Russia, particularly as an exporter of Russian and possibly Kazakh gas to Turkey via the Blue Stream pipeline (now under construction and due to deliver first gas to Turkey by the end of this year). The company has a strong relationship with Gazprom and is the operator at Karachaganak, the giant gas and condensate complex in north Kazakhstan where efforts are currently focussed on expanding condensate output from 90,000 b/d at present to 180,000 b/d by end-2004. Eni could be extraordinarily useful to the Kazakh Government as it seeks to extract the best possible transit deal for its hydrocarbons from a Russian Government and transport system that remains generally antipathetic to handling exports from what could be considered rival producers.

Azeri transit problems

Azerbaijan's transit problems are no less complex than those of Kazakhstan, but the complexities are more commercial and environmental than political. And while Kazakhstan will have, with CPC, a line available to handle the next few years of available export produce, Azerbaijan's current capacity is straining at the seams. This means that a decision on a large scale export system – referred to in Azerbaijan as the Main Export Pipeline – has to be taken soon in order to re-start a somewhat stalled expansion programme at the country's main offshore field complex and to provide facilities for future oil exports.

What makes the problem all the more complex is that not only are the decisions on expanding output at the Azeri-Chirag-Guneshli deepwater concession intimately intertwined, but development of, and export from, the nearby Shakh Deniz gas field is also linked in to the main oil field and pipeline developments.

BP is both the operator of the Azerbaijan International Operating Company's (AIOC) Azeri-Chirag-Guneshli complex and of the Shakh Deniz gas field, considered to possess between 0.7tn and 1tn cm of recoverable reserves. The company is currently on the verge of the most important set of decisions that the Azeri oil industry has had to face since the Azerbaijani Government and State Oil Company of Azerbaijan decided in 1993–1994 to seek foreign investment in the country's oil industry by means of production sharing agreements.

The London-based giant and its partners in the sponsors' group for the Baku–Çeyhan pipeline will decide by June 2001 whether or not they will commit $120mn to carrying out a detailed engineering study for the planned line. If they make this commitment then, almost imperceptibly, the study is likely to segue into actual construction. Project development will become project implementation. A commitment to carry out the study will imply that the sponsors have accepted that the project is commercially feasible and, above all, that there is, or will be, sufficiently volumes of oil to fill the projected 1mn b/d capacity pipe within a reasonable period following the completion of actual construction. What constitutes a reasonable period remains open to question. Should the engineering study be approved, the plan is for a smooth transition to physical construction with the pipe ready for actual use by late-2004 or early 2005.

But there is no way that Azerbaijan alone will be producing anything like 1mn b/d of oil for export by that date, and while some elements in Kazakhstan are genuinely interested in using Baku–Çeyhan for transit or carriage of Kazakh oil (which would first be ferried to Baku by tanker or barge), none of the major established producing ventures are ready to commit specific volumes to the line.

Assertions by US diplomats of official Kazakh support for Baku–Çeyhan have tended to muddy the waters; the Kazakhs themselves appear to view the pipeline as one option amongst many, while the companies most closely engaged in developing Baku–Çeyhan fully realise that it will essentially have to rely on Azeri input to get off the ground.

But, if Baku–Çeyhan goes ahead – BP would like writers to say when Baku Çeyhan goes ahead – the way is then cleared for a programme of sustained capacity increase at AIOC and for an expanded exploration and development programme of some of the other 20 PSAs approved by Azerbaijan. BP is due to unveil in the third quarter of this year its plans for raising output from a current level of 120,000 b/d to around 400,000 b/d by, perhaps, end-2004 – a major step on the way to delivering its eventual target for output to plateau at around 800,000 b/d.

Shakh Deniz gas exports

At the same time, BP is also getting to grips with the question of gas production and export from Shakh Deniz. Azerbaijan and Turkey, in March, signed a sale and purchase agreement which will deliver – once production has reached that level – 6.6bn cm/y of gas. Azerbaijan had hoped for a sale ramping up to 16bn cm, and with first phase development at Shakh Deniz costing between $2bn and $2.5bn, there is clearly scope for an expansion of throughput towards the end of the decade.

BP has already started work on refurbishing existing gas pipelines in Azerbaijan which would be used for initial deliveries, but a more substantial sale requires a full-scale gas line. Turkey's Botas state pipeline company is likely to play a key role in overcoming this problem. The main Botas goal at present is the confirmed physical construction of the Baku–Çeyhan oil pipeline. But there are continuing questions concerning the cost of this project. Botas has said it can be done for $2.4–$2.7bn, depending on technical specifications, whereas current industry estimates are that it is likely to cost around $3.3bn.

One way of reducing costs would be if it shared rights of way and facilities with a gas pipeline. Since the projected main gasline from Azerbaijan into Turkey follows that of the Baku–Çeyhan oil pipeline throughout its course in Azerbaijan and Georgia, and, conceivably, for several hundred kilometres in Turkey as well, it would appear that such a saving would indeed prove feasible. But that means that has to be a more or less simultaneous commitment to both projects.

The bottom line

The bottom line is that in Azerbaijan oil and gas developments hang together while, contrary to images purveyed by US diplomats, the immediate energy futures of Azerbaijan and Kazakhstan are not bound up in quite such an intimate fashion as once appeared to be the case.

Still, it remains true that developments in one country impact on another. The discovery of Shakh Deniz and Azerbaijan's swift moves to exploit the resource (and gas-rich Turkmenistan's inept diplomatic response) have ensured that Turkmenistan's own efforts to export its gas westwards to Turkey will be sidelined for the next few years. But Kazakhstan and Azerbaijan are deploying their own resources skilfully in this latest bout of energy diplomacy.

Developments on the ground may be less spectacular than was once expected, but the bottom line is that developments are taking place. Oil production has begun its long climb upwards, even if we do not know quite how high it will soar, and the facilities are being put in place to bring that oil to market. And, in Azerbaijan's case at least, gas exports look set to accompany oil exports.

Think big, start small, scale up

This year's e-business sessions at IP Week were typified by a new mood of realism, reports *Brian Davis*, in accordance with the title of the Accenture sponsored session 'E-business will soon be just business'.

The new mood of hard-nosed realism that is now an increasing feature of e-business in the oil and gas industry does not mean there is a lack of opportunities. The industry is heavily committed to extracting the synergies and efficiencies e-business offers. What, however, is becoming increasingly clear is that liquidity is the key. Sites that achieve liquidity levels that allow easy and reliable trade are the likely winners.

The oil and gas majors are currently working hard to consolidate web-based initiatives like Trade-Ranger, the Intercontinental Trading Exchange and Petrocosm, with new initiatives which were described by BP's Andrew Moutrie.

Paul Spence heads up Accenture's Global Energy e-commerce practice, and emphasised that the past three years 'have been a wild ride for the energy industry.' According to Spence the industry's recent record financial performance has seen average net income in 1999–2000 increase by 120%. However, the gains were mainly driven by externals like price (60%) and merger synergies (25%), with efficiency gains and other improvements accounting for just 15%. His view is that e-business offers to produce more benefits with less to boost the non-merger, non-price related gains to the bottom line.

Spence suggested that there are currently 6,000 to 7,000 e-ventures around the world. 'While a lot of attention has been grabbed by the e-spin outs and new players, this is not the main story,' he said. The traditional oil players have seized the new e-based opportunities, despite a historic reputation for being dinosaurs.

Site favourites

Spence remarked that the industry is starting to favour certain sites in the various sectors. This is starting to hint at the likely long-term winners. This disaggregation is seen in the use of favourites like Indigopool.com for property and data in the upstream area, Trade-Ranger for both upstream and downstream procurement, and sites like Chemconnect for chemicals, Levelseas for transport and storage capacity, and Retailmarketexchange and AmericanPetroleum-Exchange for retail and refined products.

Increasingly there is a move to take elements that were inside oil company operations and place them in outside marketplaces. The aim is to make the supply chain more transparent and introduce new ways of making money from trading in vertical marketplaces.

But Spence is still pragmatic and believes that the vast majority of e-marketplaces (even in the B2B sector) will fail. Pundits suggest that 80% of e-marketplaces will collapse, starting with those plucky start-ups who believed the myth of 'first mover advantage.'

Empire strikes back

In fact, Spence reckoned, 'the Empire has struck back' against the digital upstarts as big players came to recognise the opportunities. The major companies formed the alliances we see today, in mega sites like Trade-Ranger and Petrocosm. 'Now we are in a period of reconstruction which will hopefully lead to peace and stability – but I'm not holding my breath for it!' he remarked.

Accenture notes that the route to success is the amount of 'financial traction' a sector can generate. In the property sector it sees Indigopool.com and PetroleumPlace as the potential winners with over $600mn of property assets already traded. Commodity marketplaces IntercontinentalExchange (many-to-many) as well as EnronOnline (one-to-many) have already traded a truly staggering $345bn and provide the sort of liquidity that gives sector dominance. In terms of trading refined products the AmericanPetroleumExchange with 15bn gallons of potential liquidity appears a likely winner. In the chemicals sector ChemConnect and Envera with $500bn of potential liquidity are likely to dominate. In the broadly based procurement space, which has a potential liquidity of about $200bn, Accenture sees Petrocosm and Trade-Ranger as the dominant players with over 1,300 deals already completed. While moves towards a limited number of highly liquid sites is clear, just how far the consolidation will go is rather less apparent.

Market consolidation

That consolidation is already underway is shown by the recent shutdown of Chemdex and the MRO (maintenance, repair and operations) marketplace BizBuyer. The merger of Oilspot.com and Fuelquest.com and the link-up of NetworkOil with Petrocosm to give NetworkOil access to wider market for surplus equipment is another consolidation route. Another development has been the radical change of focus by outfits like e-Chemicals which have moved from intermediary to sell-side marketplace to supply chain software supplier. 'The picture has changed from enthusiasm and hype to informed scepticism,' said Spence. Today, he maintained the mantra should be: 'Think big, but smart (don't be afraid to be a revolutionary). Start with quick experiments to demonstrate proof of concept, then scale fast (with speed and awareness).'

He maintained that four barriers remain in the path. First, companies must allow Digital Darwinism to play its course. This means killing things that don't work and focussing on those that do. 'Don't struggle trying to keep corpses alive,' said Spence.

Secondly, build industrial strength into new e-business initiatives. That means avoiding vendor promises that often turn out to be dreamware or half-proven software. Spence suggested there must be a drive for industry standards and a need to get vendors to deliver solutions which link to the back-end core of business with industrial strength and scale.

Thirdly, e-business requires 'big pipes' (bandwidth) for a connected economy, but many companies still lack the scale of communication network necessary to make successful e-business happen throughout their extended enterprises.

Finally Spence suggested: 'Think Lego.' Building an effective e-business strategy requires using small, flexible modular blocks which can plug-and-play, as the oil industry will have to adapt quickly and easily to a constantly changing picture and expanding set of options in the e-world.

BP ventures into e-world

Andrew Moutrie, leads a small team as part of BP's Group Digital Business which has identified and developed over 30 new e-business opportunities. He gave a valuable insight into how BP identifies potential e-business winners, nurtures ideas and cull those that can't hack it, explains Brian Davis.

BP's initiatives were triggered a couple of years ago, impressed by the Goldman Sachs estimate that the Internet could reduce total industry costs by 5–10%. It also recognised the opportunities offered by the Internet as a new medium for communication which would encourage new and innovative ways to grow the business. 'Though BP was also aware of the hype surrounding dot.coms, it clearly recognised sources of fundamental value,' said Moutrie.

In July 1999, it focussed on a two-pronged attack, with the bulk of resources aimed at digitising the BP business, while a small team explored new opportunities. BP employed an incubator model to nurture ideas called eLab. This was developed by a few BP employees and leveraged throughout the company with business project teams, third-party suppliers and equity partners.

Moutrie maintained that corporate venturing has become a prerequisite in the oil industry due to the scale of investments associated with E&P, development and downstream operations, not simply new e-business initiatives. However, previous efforts like BP Ventures in the 1970s and 1980s — when BP explored ventures outside its core activities, from coal to nutrition – 'left some deep scars on the corporate memory.'

Developing a digital business has meant exploring models and ways of conducting business, with considerable areas of uncertainty. Faced with the old scars, BP needed to apply some lessons already learnt. Recognising that the Internet meant a fundamental shift in perceptions, the group decided to create a space to explore revolutionary ideas 'away from the day job' but with clear goals.

Although BP has an environment where innovation flourishes, it tended to be associated with the lifecycle of existing business models. So venturing offered more ways to address these issues and share risks and reward with strategic partners.

Finally there was the question of change and risk management. BP reckoned that as a successful, established business it had a substantial advantage over any start-up, offering liquidity for the new business model. Here again the key rule was 'Think big, start small and scale rapidly.' Well proven staged financing and development processes were adopted, based on the venture capitalist maxim 'You need to kiss a thousand frogs to find a prince'.

Initially BP cast the net wide, with little risk and maximum flexibility. It then evaluated those opportunities with greatest potential that the group could exploit distinctively. Promising efforts merited a little senior management attention and some seed capital.

BP used a stage-gate approach to the resourcing and management of potential e-projects. At each stage it gradually increased commitment and gave hands-off responsibility to the team that will eventually own it either as part of BP or as a separate entity. In the early growth/idea stages BP retained the flexibility to adapt to the unforeseen or halt further investment.

According to a diagram shown at IP Week, BP when evaluating a list of potential dot com investment projects typically spends from up to \$50,000 examining thousands of ideas and choosing go-ahead or kill within days. Subsequently, about 100 concepts are studied in more detail, at a cost of \$100,000 to \$500,000, over a period of weeks. Using the stage-gate approach to analysing potential developments, commitment is made to about 20—50 projects, with associated costs of \$250,000 to \$20mn over a period of months. Subsequently, projects will develop or die over a one- to five-year period.

Due to the entrepreneurial nature of e-business, 'BP quickly recognised it had a dearth of entrepreneurial skills for the early and mid-growth phase – before projects can scale to a certain level for effective stewardship,' said Moutrie. As a result it has taken a networked incubator approach, using small 'halo teams' that can leverage effective initiatives. Consequently, initiatives are spun in to the organisation or spun out.

For example, on the environmental side, BP spun in the Solar business, which is branded and wholly owned. It also invested in Greenmountain.com as it shared environmental values and offered an online marketing community. Some initiatives also spurred initiatives on their intranet like bp Virtual Village, where employees can do online banking or even flower buying.

Spin-outs included investment in Trade-Ranger, online trading exchange Intercontinental Exchange as well as OceanConnect, JetA, Flightneeds, LevelSeas and investment in ChemConnect, Altra and other industry consortia.

The key lesson has been the need to be fast and flexible. 'Digital business venturing is fast, intensive and challenges people's behaviour,' stated Moutrie. It needs clarity, internal champions, careful governance, a shared vision, the backing of a winning team and focus. Most important: 'Don't try and get it all right from the start.' The trick is 'do, learn, do' in the world of online business. The real value of e-business is not simply the technology but the need to focus on valuing relationships.

Production platform on BP's Andrew field

Cost reduction in plant engineering projects

It is early days for integrated IT project solutions. However, the tools and platforms are now in place so that organisations can take the next step forward towards extensive cost-savings and much more effective ways of working in partnership. *Tony Christian*, Services and Technology Director, Cadcentre, reports.

Information technology (IT) has become essential to the operation of every business of any scale. But there are huge variations in the ratio of business benefit realised per dollar invested in IT. One level of benefit comes from efficiency – automating existing tasks – but far greater benefits can be realised by taking a broader view and exploiting opportunities to 'work smarter.' For example, by deploying integrated IT solutions across manufacturing processes, or even entire supply chains, and linking them with enterprise-wide finance systems, organisations have achieved spectacular cost savings by identifying areas where unnecessary capital is tied up in stockholding, in unpaid invoices and in idle plant.

Generally, IT has failed to produce similar results in large-scale plant engineering projects. Such projects are complex and costly. Sophisticated IT tools are routinely used by individual functions within a project – indeed, they are essential. However, it has proved difficult to adopt an integrated approach, and therefore to realise the benefits that would accrue. For example, the industry average for material surpluses at the end of a project continue to run at 5% of the overall cost of the project – a figure that has remained unchanged for decades.

Achieving cost savings

So, it is interesting to look at how other industries have achieved the savings that they have and, in particular, at the adoption of enterprise resource planning (ERP) solutions. ERP is the manifestation of the concept of integrated IT from finance to human resources (HR), and from supply chain management to global logistics. More recently, organisations have gained further savings by integrating these 'back office' systems with customer facing applications such as customer relationship management (CRM). They have one central 'version of the truth' about customer records, about orders and deliveries, about product specifications and about pricing and finance.

This means that information does not need to be re-entered into different systems, but that each area within the business – finance, HR, procurement, sales, logistics – has its own 'filter' through which it can view the core data. In turn, this means that business decisions can be made on the basis of accurate, current data – reducing the time taken to plan forward business, to fulfil customer orders, and to get products to market quickly.

Most companies in the process industries have joined peer organisations in industries such as finance and utilities in adopting ERP as an enabler of new processes in the 'business domain.' They are increasingly using systems such as SAP R/3 to integrate CRM, marketing and financial management, having replaced 'point solutions' with a single integrated framework.

We can therefore come back to plant engineering and consider applying similar principles to projects involving the design, engineering, fabrication, construction and commissioning of large-scale plants. An integrated approach to IT support for such projects, analogous to ERP for the business domain, would yield substantial benefits in terms of cost reduction and schedule compression. The financial benefits accruing from early start-up of an oil rig or drilling platform or pharmaceutical plant are huge.

Barriers to IT integration

So, what has hindered the realisation of integrated IT support for plant engineering projects? There are two main sets of challenges faced by organisations that want to reduce costs and time scales through the effective use of integrated IT – cultural and organisational barriers, and technology and data barriers.

The first exist because of the way in which the process plant engineering sector has evolved over time. Projects are typically broken down into discrete lifecycle phases with spans of responsibility defined by those phases. Since participants in a project naturally focus on the issues within their span of responsibility, 'local' benefits win against broader, potentially larger overall benefits. As a result, the relationship between owner/operators and their (sometimes numerous) engineering partners has often been adversarial, with conflicting interests leading to reduced cooperation between the engineering firms and the client and even between the engineering firms themselves.

This decomposition of the project workflow is also reflected in the way in which projects are managed internally within companies, adding to the barriers to integration. Different processes and applications tend to be managed separately, by different experts, using different tools and different data. The IT industry has developed tools to support the individual processes, resulting in an environment of fragmented solutions requiring considerable re-entry of data and duplication of information from one application area to another, either through re-keying of data or through application interfaces that translate data from one format to another.

A further organisational issue hampering the development of integrated IT applications for large plant engineering projects is that every project is regarded as a 'business.' The costs and benefits of IT are typically considered in the context of the single project or business, again making it harder to justify investment in 'generic' developments.

The second set of challenges, those relating to technology, are being met by significant advances in database and networking capabilities and by the continuing strides in improved computing performance. Moore's Law defining the pace of increase in computing power is undisputed – and the power of current desktop computers has solved a lot of issues for users of engineering applications. Some of the individual applications used on plant engineering projects are very sophisticated, as noted earlier, and tend to be very resource and power hungry. It is only in the past couple of years that hardware and standard software such as Windows NT have developed to an extent that they can handle memory and processor intensive applications such as top-end 3D computer aided design and complex process simulation tools.

Improved database management capabilities have allowed the creation of an integrated set of project engineering applications, all having access to the same central data. Furthermore, the long-standing ambition to re-use the data produced during the asset creation activity downstream in the operation and maintenance of the plant can be realised.

Taking a broader perspective

Many companies now recognise that achieving significant business improvements requires them to take a broad, end-to-end view of the project processes. They have therefore moved IT up the strategic agenda and are looking for ways to exploit technology far beyond the traditional approach of using it to automate a particular department or function.

With these issues and the potential opportunity offered by an effective integrated IT environment in mind, Cadcentre has developed a suite of integrated applications to support the total project lifecycle and the MRO (maintenance repair overhaul) and modification activities through the operating life of the plant. The resulting engineering IT environment, developed in partnership with leading process industry engineering companies together with owner/operators such as Kvaerner and Du Pont, supports the radical business improvements in plant engineering and operations being sought by owner/operators and EPC (engineering procurement contractor) firms alike.

The priority areas for improvement include:

- Standardisation and design re-use.
- Supply chain re-engineering.
- Globalisation of projects and low-cost engineering.
- Schedule compression.
- Quality and regulatory compliance.
- Risk management.
- Improved estimating.

To support these objectives, the project engineering IT environment must comprise a comprehensive, world-class set of applications and effective, robust integration and networking technologies. Process sector organisations often need to build new plants in remote places, far away from headquarters and development sites. A head office may oversee and manage a project, but pipework design may be done in Kuala Lumpur, while specialists in London may produce steelwork. Increasingly, the larger projects are global undertakings, with many participants working simultaneously in many locations, so the ability to provide appropriate, reliable access to the shared project data and applications is essential.

Cadcentre's project engineering IT solution addresses the key areas of:

- front-end engineering;
- engineering data management;
- 3D design and detailing across all disciplines;
- project control; and
- materials control.

Process in practice

There are some good examples of the benefits that effective use of an integrated project IT environment can bring. One such example is BP's Andrew development in the North Sea (see photo). Andrew was chosen by BP Exploration to serve as a 'breakthrough' challenge in the company's drive to improve business performance. Design and construction of the offshore platform and facilities were achieved under a pioneering alliance contract between BP and seven contracting companies. The field came onstream in June 1996, producing oil six months ahead of schedule and more than £80mn under budget.

The Andrew project – documented in detail in *No Business as Usual* by Terry Knott (BP, 1996) – is a success story for a number of reasons. The first is that contractors for the project were selected on the basis of their ability to work positively as part of a team. The contractors and BP set performance targets together, and as a result were able to save £40mn from the money sanctioned to be spent. And, because the oil platform came onstream six months early, it was productive earlier than expected, increasing total revenue overall.

John Martin, Project Manager at BP, commenting in *No Business as Usual*, said: 'In 30 years in the oil industry, and 20 within BP, I have no experience of a project not touching a penny of its contingency money, nor coming in six months early.'

The key to the success of the Andrew project, therefore, was that the participants recognised and tackled both the technology and the organisational barriers to successful integration. We can therefore add a third ingredient for successful project integration to the two mentioned above (world-class applications and integration technology) – the right approach.

The right approach

The majority of ERP implementations, in spite of their very solid integration proposition, fail to deliver the anticipated business value. Those that do, however, seem to have a common characteristic – they recognised that the deployment of integrated IT solutions is essentially a business change programme (with a large IT component) and managing its introduction accordingly is vital. The same applies to plant engineering IT.

Solutions developed by companies such as Cadcentre will enable more organisations to adopt these new ways of working, particularly when they are working with multiple contractors in different countries across the world.

It is early days for the process engineering sector, and early days for integrated project solutions. But the tools and platforms are now in place so that organisations can take the next step forward towards extensive cost-savings and much more effective ways of working in partnership. It may never be possible to plan an oil platform or a process plant down to the very last nut and bolt, but organisations can certainly develop a far more accurate view of processes, materials and project timelines than ever before – and realise the resulting benefits.

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Rising to the challenge of tighter specifications

Can European oil products customers travel more miles and satisfy Kyoto emissions requirements, meet Auto-oil standards and cope with rising crude prices? *Tony Parker, Glenn Liolios* and *Colin Harvey* of Stratco Incorporated* examine the impact on refinery operations of the arduous demands being placed on them.

It seems there is no let-up on the pressures for European refiners. Although margins have for the moment recovered from the doldrums, society at large is demanding what appears to be ever more conflicting priorities. This is to be expected as mankind in general becomes more affluent and knowledgeable of world events and individual pressure groups have the power and opportunity to voice particular viewpoints and concerns.

The recent wave of public outcry across Europe over the increase in gasoline and diesel prices came at the same time as widespread flooding across the Continent sparked off demands from governments and pressure groups alike for a global solution to climate change and ever-increasing energy demand. Even though the recent governmental talks in The Hague at the end of 2000 failed to reach agreement on moving the Kyoto Protocol forward, there is no doubt that the oil industry will be at the centre of the continuing debate on economic progress against local and global pollution.

Over the past three decades the downstream part of our industry has responded admirably by revamping refineries to produce an ever-whiter sales barrel, steadily producing more jet, diesel and gasoline. In this way finite crude resources are utilised for applications where there is no suitable alternative and may be considered as a step to sustainable development.

Much effort on the political and scientific front is going into developing new forms of transport fuel such as gas and hydrogen, but the traditional white products of the crude oil barrel will remain an economic necessity for the foreseeable future. For example, in aviation there would seem to be no acceptable alternative on the horizon to help service the ever-growing appetite for air-travel.


Figure 1: Stratco alkylation unit

Auto-Oil programme

The new European specifications for road transport fuels being introduced now and in 2005 under the heading of the Auto-Oil Programme is a challenge. In order to achieve the changes required by the new legislation, the refiner is being forced to produce lower and lower percentage cuts of the white transport products at a time when they continue to increase in demand.

The final outcome of the new and impending specification changes were much more stringent than anticipated by the oil companies. They entered into a long, costly and what was hoped to be a rational and balanced review process, in collaboration with the car manufacturers and the European Commission. Part way though this process it became clear that the political pressure from the environmentalists, either directly on local governments and the European Parliament or on the car manufacturers, to produce lower CO_2 (carbon dioxide) and other emissions would have a decisive effect.

For diesel, increasingly stringent requirements for sulfur, cetane, and density are required. For gasoline, the refiner seems to be driven into an even smaller box with tighter specifications for sulfur, benzene, aromatics, olefins and volatility whilst being required to meet the same octane targets. See **Tables 1 and 2**.

These diesel and gasoline specification changes, coupled with the ever-increasing jet fuel requirement, reduce the proportion of finished transport fuels that can be manufactured from the crude intake, even with conven-

	1999	2000	2005
Sulfur (ppm max)	500	350	50 (10)
Density (kg/m³ max)	860	845	(825)
Cetane number (min)	50	51	(56)

Table 1: Future European diesel specifications

	1999	2000	2005
Sulfur (max ppm wt)	500	150	50 (10)
Aromatics (max vol%)	No spec.	42	35
Benzene (max vol%)	5	1	1
Octane (RON min)	95/98	95/98	95/98
Olefins (max vol%)	No spec.	18	– (10)
RVP (max Kpa)	80	60	–

Note: Figures in parenthesis are not yet finalised.

Table 2: Future European gasoline specifications

tional conversion processes such as catalytic cracking as well as deeper desulfurisation. Another consequence is an increasing array of 'orphan streams' such as the heavy diesel and naphtha components as well as butane that are being driven out of the gasoline pool by more stringent vapour pressure requirements.

Blending skills not enough

Over the past few years, poor returns to the downstream sector, overcapacity and low crude oil prices providing no salvation from the upstream sector, have concentrated management attention of all companies on rationalisation plans both at the corporate and refinery level. This has been coupled with a tight rein on refinery capital spending directed only to meet the most urgent specification changes.

Where capital expenditure has been approved for specification changes it has tended to be focused on desulfurisation, particularly of diesel, where there is no easy blending or crude selection alternative. In order to meet the future gasoline sulfur specification post treatment of FCC (fluid catalytic cracker) naphtha becomes essential, but adds a further blow to the octane pool already hit by the benzene and aromatics specification changes and the necessity to include less butane to meet the vapour pressure specifications. With the overall gasoline pool remaining long, refiners have relied on a few high-octane components to meet the more stringent product specifications.

Isomerate, MTBE (methyl tertiary butyl ether) and alkylate are the most widely traded commodities for this purpose. However, it may not be long before MTBE is banned or limited if Europe follows California in this matter, as it has on many other environmental trends. Although the benefits of MTBE are numerous it has been found in ground and surface water, creating public concern. Between 5% and 10% of drinking water supplies in areas consuming reformulated gasoline have shown detectable levels of MTBE and a number of surface waters have also tested positive for MTBE at low levels. Alkylate and, to a lesser extent (because of its volatility), isomerate, remain ideal components in the world where octane, volatility, benzene and aromatics remain at a premium.

More refinery refitting

The European refining base is now centred in large complexes with upgrading supplied by cat cracking or in a few cases hydrocracking. Most large cat-cracking refineries already have alkylation units installed. However, there remains considerable scope for low cost de-bottlenecking of existing units to meet new gasoline specifications.

Non-typical alkylation feedstocks such as propylene and amylenes can now be economically alyklated thus increasing the availability of suitable upgrading feedstock. Although alkylate has been termed the 'perfect gasoline blending component' by several automobile and environmental experts, most refiners around the world have hitherto avoided alkylating their amylenes due to an anticipated high acid consumption. Under previous vapour pressure and olefins specifications it was also common to blend C5 olefins directly into gasoline, a practise that will become very difficult for most sites after 2005. Refiners should re-evaluate the economics of amylene alkylation based on rising alkylate blending values and the new segregated olefin feed processing technology now available. This technology is currently being commercially utilised to meet California's difficult gasoline specifications.

Stratco is a world leader in licensed alkylation technology (see **Figure 1**) and has recently expressed its confidence in the European market and the potential for the new technology by opening a technical office in London last September.

European refiners now have to finalise their plans for meeting the challenge of maintaining or increasing the yield of transport fuel out of the crude oil barrel whilst meeting the next round of more stringent specifications. There is nothing new in this; one only has to look at the situation during the phase out of lead additive in gasoline to understand the difficulties. Although desulfurisiation capacity is going to be installed to meet the new specifications, there is little or no volume gain to offset the loss of the product-cut due to the other tighter specifications.

In the case of gasoline, those refiners lucky enough to have isomerate have a blending component which can extend the gasoline production capability, or at least negate some of the reduction due to the tighter benzene, aromatics and volatility specifications. Equally, alkylate can offer a similar role and will increase in importance both in-house and as a traded blending component.

There is still hope to extend the availability of the 'ideal blending component' through the new technologies available for propylene and amylenes conversion. And boosted further if coupled with the opportunity for new builds and conventional de-bottlenecking on FCC refineries to bring the overall process plant line up to the levels which exist in the US.

Yet again capital is required, although incremental capacity is always cheaper. However, it would appear that the downstream industry can yet again rise to the challenge and satisfy the divergent interests of environmentalists, motorists and governments.

**Glenn Liolios is Stratco's Vice President with responsibility for alkylation licensing activities. Tony Parker is the company's Manager of European Business Development recently heading up the new European office after leaving BP. Colin Harvey, former Downstream Managing Director of Shell UK and past Vice President of the Institute of Petroleum advises Stratco on international issues.*

Radical changes afoot

Recent studies indicate that LNG trade is continuing to grow. However, radical changes look set to impact the market. *Fred Thackeray* reports.

Growth of about 6% in Asian imports of LNG was recorded in the first three-quarters of 2000. According to estimates by consultants Poten & Partners, Japan, South Korea and Taiwan together imported a total of 54.1mn tonnes (74.7bn cm), compared with 51.1mn tonnes in the corresponding period a year earlier. (See **Table 1**.)

These three countries account for around 75% of total world imports of LNG. On the basis of their estimated imports, rough estimates made by the author suggest that overall world LNG trade probably increased in 2000 by about 7% to some 96mn tonnes. This rate of growth corresponds with the past long-term average rate, up to the time of the Asian economic crisis in 1998.

The growth rate was lower than the increase of 10% in 1999, but it can still be said that, so far, the LNG business continues to participate strongly in the world's love affair with natural gas. Whether it continues to do so in the next few years will rest largely on the eventual outcome of key developments in the industry that are already underway. These include:

- A substantial surplus of liquefaction capacity that began to appear two to three years ago continues to dominate the LNG markets.
- Spreading liberalisation of electricity and gas markets throughout the world is driving down CIF (carriage, insurance and freight) contract prices.
- Significant changes are taking place in the pattern of international LNG trade – slower growth in Japan's imports; prospective big new markets in China and India; new sources of supply in Trinidad, Nigeria and Oman, and three or four other sources in prospect.
- The US market has emerged as a new major target, with an apparently chronic shortage of natural gas supply and, at present, almost unbelievably high prices.
- Short-term and so-called 'spot' contracts have become an increasingly important factor in the LNG business.
- Remarkable reductions in liquefaction costs have been obtained in at least two major new plants. Cost reductions have also been achieved for LNG tankers.
- The Fischer-Tropsch gas-to-liquids technology (GTL) has attained commercial status, providing an alternative means to monetise remote natural gas reserves by selling production into hungry markets. Whereas new supplies of LNG enter markets already in potential surplus, additional supplies of GTL diesel would represent only a small increment in supplies of automotive fuels.

Surplus capacity dominates

Currently, there is excess liquefaction capacity worldwide of around 14bn cm/y, according to a recent estimate published by BG International. This is equivalent to some 15% of present world demand.

On top of this, new liquefaction capacity already fully committed in three expansion projects will add 24bn cm/y, or the equivalent of half the prospective increase of demand up to 2003, if this continues to expand at 7%/y. Growth of demand at this rate would total just over 49bn cm (35.5mn t) by 2003.

The three expansions at existing plants, totalling about 24bn cm/y, comprise:

- two new trains, each of 4.5bn cm, which are being built in Trinidad for Atlantic LNG to go onstream in 4Q2002;
- two additional trains at Bintulu in Malaysia, each of 5.5bn cm – one for completion in 4Q2002 and one for 3Q2003; and
- another train of 4bn cm in Nigeria, due onstream in 4Q2002.

More significant for the state of the market in the next few years is the very large number of other incipient proposals. These are being eagerly promoted both by existing LNG exporters and by new would-be exporters, seeking markets for abundant proved reserves. Proposals for new liquefaction capacity publicised to date total around 120bn to 130bn cm/y as shown in **Table 2**. This figure, plus the 24bn cm/y already firmly committed, amounts to at least 144bn cm/y – or three times the growth of world demand for LNG which will be achieved between 2000 and 2006 if it continues at the past annual average of 7%.

Whilst many of the proposed ventures will inevitably be delayed or not realised at all, the conclusion is that there is likely to be a continuing surplus of potential supply and downward pressure on market prices for several years to come.

Competition hits the markets

The consequence of excess capacity has been an increasing use of short-term contracts ranging from one-off single voyage deliveries to deals of up to five years. These are in sharp contrast to the customary 20- to 25-year contracts that have hitherto formed the bedrock of the international LNG business. Such contracts – sometimes misleadingly described as 'spot' – accounted for only some 3.5bn cm/y, or 4% of the total LNG trade, in 1999, but undoubtedly for a much higher figure last year.

By 2010, according to an estimate by Andrew Walker of BG International*, the total of short-term trades could lie within a range of as much as 30–80bn cm/y. The upper figure would be equivalent to no less than 35% of total trade, which the speaker forecast at 235bn cm. The very high figure of 35%, however, is the maximum that Walker thought feasible without a fundamental restructuring of the LNG business. It could come about partly due to the fact that contracts for some 50bn cm/y will fall due for renewal in the coming ten years. Buyers will be pressing for improved terms – as they already are doing – and sellers will be in a position to respond since their past investments in this capital-intensive business will have been already written off.

Patterns of trade change sharply

For LNG exporters the major changes foreseen in the pattern of international LNG demand are reflected already in the big plans for expansion proposed by Qatar (**Table 2**). With India expected to become a major LNG importer it is a key factor that the one-way distance of about 2,500 km from Ras Laffan to Dabhol on the coast of Maharashtra in western India is only one-quarter of the distance of 11,000 km to either Japan or to Montoir in France. Conversely, the distances to India from Asia's big exporting terminals in Indonesia and Malaysia are much greater than to their established markets in Japan, South Korea and Taiwan. The distance factor will weigh even more heavily against LNG exports from the Burrup Peninsula in Western Australia.

A number of elements in the above picture could turn out differently as the scene evolves. One change, in particular, which would make a considerable difference would be resumed faster growth of LNG imports by Japan. This could occur if current hostility to expanding nuclear power forces the electricity generators to further increase their use of natural gas.

An intriguing development in the growing competition for changing Asian markets is the endeavours by Shell to buy a controlling stake in the Australian company Woodside. Shell already holds 34% of the company and has been seeking to increase this, which would give it a dominant position in LNG export developments both offshore northwest Australia and in the Asian markets generally. Woodside, however, has twice rejected Shell's offers, claiming that they are too low.

Major cost reductions

Contrary to repeated assertions over many years that significant reductions in liquefaction costs are not physically possible, remarkable reductions have been achieved in two recent projects and even further reductions have been foreshadowed. In the context of sharpening price competition the achievement of similar results for other new projects will be essential to ensure continuing expansion of the LNG trade.

In part, the cost savings are attributable to improvements in management techniques. Thus, in the construction of the first 4bn cm train of the Atlantic LNG plant in Trinidad, the savings of some 30% below the industry norm have been attributed by BG not to the Phillips Optimised Cascade Process used, but rather to a long list of factors such as 'the use of functional specifications for equipment design; the use of vendor design margins with no project specific margins added...'

Similar cost savings have been claimed also for Shell's new plant in Oman. This is attributed to significant improvements over the past five years in the patented technologies that the company uses, including a newly developed 'double mixed refrigerant technology.'

**Speaking at an IBC Conference in London in October 2000.*

	Year 1998	Year 1999	% incr 98–99	Jan–Sept 1999	Jan–Sept 2000	% incr 99–00
Japan	66.1	69.3	4.8%	53.5	55.3	3.4%
S Korea	14.3	17.5	22.5%	14.7	12.7	15.7%
Taiwan	4.7	5.4	13.8%	4.3	4.7	9.3%
Total	**85.1**	**92.2**	**8.3%**	**70.5**	**74.7**	**6%**

Sources: BP Annual Statistical Survey of World Energy, 1998–1999; *Poten & Partners.*
Note: Jan–Sept 1999–2000 data published by Poten & Partners in tonnes has been converted to bn cm using a factor of 1.38bn cm = 1 tonne.

Table 1: Asian Imports of LNG, 1998–1999, and Jan–Sept, 1999–2000 (bn cm)

Exporting Country	Companies	Capacity (bn cm)	Possible onstream year
Angola	Texaco	5.5–11	2005 (first stream)
Australia	Australian LNG	5.5–11	2004 (first stream)
Egypt – four projects		23.3	na
	Shell	(5.5)	na
	BP	(8.8)	2004
	BG/Edison	(4)	2004
	Union Fenosa	(5)	na
Indonesia (Tangguh)	BP/BG et al	8.3	2004 (first train)
Iran	BG	9	2006
Nigeria	Shell	11	2005–2006
Norway	Statoil	8	2005–2006
Oman	Shell	4.5	2005
Qatar – two projects		23	–
	Qatargas**	(4)	2005
	Rasgas***	(19)+	2004–2007
Sakhalin 2	Shell	10	2006
Venezuela – two projects		8.3	–
	Exxon/Shell	(5.5)	2005
	Enron	(2.8)	2003
Yemen	TotalFinaElf	6.2	na
Total*		**122.6–133.6**	

** Atlantic LNG has spoken recently of a possible fourth train of 4.5bn cm in Trinidad.*
*** QGPC, Mobil, Total et al.*
**** QGPC, Mobil et al.*
+ According to a statement by the Minister of Energy, Abdullah Bin Hamad Al Attiyah.

Table 2: Publicised plans for new liquefaction capacity

	1999	2010	% incr
Asia	92.2	165.1	79%
Europe	27.5	60.4	120%
N & S America	4.6	13.8	200%
Total	**124.3**	**239.3**	**93%**

Source: Ocean Shipping Consultants

Table 3: Forecast of regional LNG consumption (bn cm)

Smart wells in deepwater

As the oil and gas industry ventures into the ocean depths it becomes increasingly important to maximise production from every well because of the enormous drilling costs. One way of achieving this is to tap several different production zones with each well; electronic intelligence can then be used to monitor and control flow in the different production streams. This smart well technology is now being adopted for some of the most high profile deepwater projects. *Jeff Crook* reports.

One approach to tapping different production zones involves perforating the well at various levels, with packers inserted to isolate the different zones. The production tubing string is then designed to convey the product from lower zones, past the isolating packers at higher levels, to the surface, with components, such as slide valves, to switch between the different production zones. But a more elaborate 'multi-lateral' well design is needed when the zones are not stacked one above the other.

Multi-lateral wells

A multi-lateral well has branches that resemble the spreading roots of a tree – these branches can be drilled towards the end of the life of the field, as production is declining. There have been considerable advances in this technology over the past few years and coiled tubing drilling now provides a cost-effective method of boring a side-track, eliminating the need for a full-scale drilling rig. Coiled tubing drilling systems can be used to target pockets of oil or gas many hundreds of meters away from the original bore of the well.

Completing a multi-lateral well to bring it into production must take account of the complex geometry of the transition points between the main bore and the side-tracks. The production paths from the different zones will need to be connected at these transitions points, but arrangements will also have to be made for closing off depleted zones. There is also a need for accessing each of the branches for logging as well as workover operations. Ingenious transition components are being designed for these functions.

One major advance announced towards the end of 2000 was the completion of a well in the Ghawar field in Saudi Arabia which permits access to two side-tracks from the main bore without the need for a full-scale drilling rig. This was described as a 'world first' by Sperry-Sun Drilling Services, a division of Halliburton Energy Services. Claiming to be a world leader in multilateral well technology with over 250 installations around the world, Sperry-Sun worked with the Saudi Arabian Oil Company (Saudi Aramco) to install the 'multiple through-tubing re-entry system' on the Ghawar field.

This installation incorporated a 'self-locating lateral re-entry system' (LRS-SL™) which eliminates the need to pull the completion string from the well should access be required to a lateral for stimulation, zonal isolation or data acquisition. Sperry-Sun says that LRS-SL utilises a window system that is an integral part of the production string. The system is equipped with landing profiles and seal bores to enable setting of through-tubing whipstocks for lateral access or for inserting isolation sleeves for lateral flow control. The whipstocks can be deployed by wireline or coiled tubing.

Smart wells

The aim of smart well technology is to monitor conditions within each production zone and to use this data to control flow streams from the various levels or branches within the well. Intelligent completions are already in service – these completions enable the configuration of the well to be altered as downhole conditions change, without the need for a costly well intervention operations.

Data from downhole sensors are transmitted to an intelligent electronic system at the surface in real-time. The intelligent system then activates valves within the well bore to reconfigure the well. The data from the downhole sensors can also be relayed to the company head office, many thousands of miles away. The intelligent system would automatically cut-off production from zones that had become un-productive or water-logged, whilst allowing flow from more productive zones to continue unrestricted.

Whilst the control principles are relatively simple the technology presents many challenges, both because of the harsh reservoir conditions and because of the tight confines of the well bore. Sensors, valves, actuators and control lines must provide many years of reliable operation in these harsh conditions without intervention for repair or replacement. It is also important that the components do not restrict the well bore, since this would lower overall production rates.

The intelligent completion may also have to be integrated with other downhole systems, such as downhole pumping and downhole separation. Downhole pumping is a well established technology that enables the production rates to be boosted. Downhole separation is a more recent innovation that reduces the quantity of water that is brought to the surface. The water and oil fractions are separated from one another close to the reservoir; the water is then pumped back into the reservoir, whilst the oil is brought to the surface on its own.

Downhole sensors and actuators

The downhole sensors used today are designed primarily to measure pressure, temperature and flow. It is now common practice to install these downhole sensors on a permanent basis within deepwater wells. The future will see even more rugged and resilient sensors based, perhaps, on fibre-optic technology. There is also a trend to use data transmission systems, rather than continuous signals, to transmit data from the sensors to the surface. This trend will become more firmly established as agreement on data communications standards is reached.

More sophisticated sensors have also

become available to measure complex functions, such as water cut, gas fraction and multiphase flow measurements. This trend is illustrated by a recent application of a downhole watercut meter in an operational well (C-27) on the Captain field in the North Sea. This Aquaphase™ meter was supplied by Expro North Sea, part of Expro International Group.

Texaco, and its partner KCCL, deployed the downhole water fraction meter to compliment the existing downhole instrumentation during a transition phase when the C-27 well will change from continuous oil production to continuous water production. 'The performance of the meter in this transition phase will be critical to the overall success of the project,' said Jim Clark, Senior Production Engineer on Texaco Captain during August 2000.

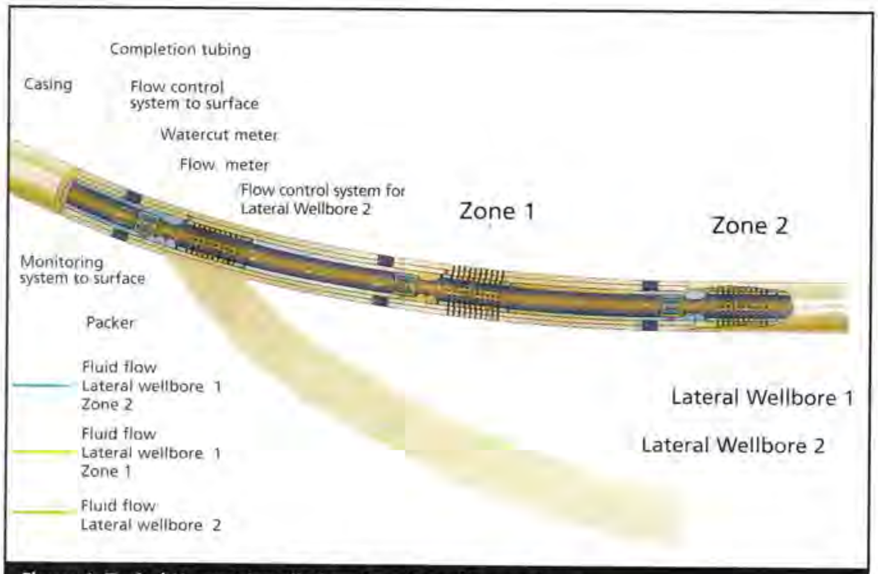

Figure 1: Typical Harvest installation. Courtesy of Expro Group.

The powering of downhole actuators for intelligent completions is another tough technical challenge; equipment standardisation will also be a factor in this product market. Simple hydraulic actuators can perform the downhole functions, but installation of these devices greatly complicates the well completion. The equipment must be very compact to prevent the actuators and supply lines from restricting the well bore. One possible innovation in the future may be to use long-life batteries to power electric downhole actuators. This solution would eliminate the need for a power supply cable from the surface.

Deepwater applications

Smart well technology was reportedly used by the Italian oil giant Eni as part of the deepwater development of the Aquila field in the Adriatic Sea offshore southeast Italy. This development came onstream in April 1998 and consisted of two subsea wells in water depths of 850 metres connected back to the Firenze floating production storage and offloading (FPSO) vessel. The wells were drilled with substantial horizontal sections to maximise production.

There have also been a number of intelligent completions in the Gulf of Mexico. The first of these was described in some detail in a technical paper presented to the Offshore Technology Conference (OTC) in Houston during May 2000.[1] The development involved subsea wells in a water depth of 3,300 ft – each well penetrated two disconnected production zones, with packers suspended in the well bore to isolate the zones from one another.

The intelligent completion allows the operator to monitor conditions within each production zone and an electro-hydraulic system enables the operator to select the zone from which fluids are to be produced. The paper makes it clear that the use of intelligent completion technology required careful planning and directly affected many of the key areas of well design including the tubing hanger and subsea interface specification.

The Norwegian North Sea Snorre B development is an example of a state-of-the-art project in which smart well technology has been incorporated into the subsea design from the outset. This project consists of a 57,000 tonne semi-submersible floating production unit (FPU) which is to be moored in 350 metres of water around 210 km northwest of Bergen, offshore Norway, during summer 2001. The unit, which lies 7 km north of the existing Snorre tension leg platform (TLP), will be connected by flexible risers to wells on the seabed.

The main subsea functions for Snorre B are monitored and controlled from a Siemens Simatic operator station on the FPU with data communicated at high speed from sensors on the seabed using a Profibus DP protocol on a dual redundant bus system. The Simatic operator station will also present downhole information via a newly developed downhole instrument and control (DIACS) system. Siemens says that the DIACS system also enables the well production to be taken from several different zones of the reservoir.

Smart well technology will also play a part in the Na Kika project, the deepest project yet planned for the Gulf of Mexico. This $1.3bn project is operated by Shell Exploration and Production Company (SEPCo) in partnership with BP. It is located around 140 miles southeast of New Orleans in water depths ranging from 5,800 ft to 7,600 ft and will involve a permanently-moored FPU connected by flexible pipes to subsea wells. The project will recover an estimated 300mn boe from six independent fields: Kepler, Ariel, Fourier, Hershel, East Anstey and Coulomb.

Shell joint venture

Shell announced last year that it was to establish a joint venture with Halliburton to market smart well technology on a global basis. The joint venture company, called WellDynamics, will market Halliburton's SmartWell completions technology and Shell's iWell technology to the oil and gas industry on a global basis, from offices in Aberdeen. Halliburton's SmartWell technology is provided by Petroleum Engineering Services (PES), a wholly-owned subsidiary of the oilfield service conglomerate.

Shell has expressed the view that the most promising applications for intelligent completion solutions are deepwater, subsea, and remote locations – these are all locations where well support tends to be costly. But the company believes that as the technology develops, intelligent completion solutions will be used to add value to a broader segment of the market, including land and platform developments. The oil major believes that the total market for intelligent completions could reach more than $1bn in the next 10 years.

1. 'Case Study: First Intelligent Completion System Installed in the Gulf of Mexico.' Presented at OTC 2000 by V B Jackson, SPE, Halliburton Energy Services and T R SPE Petroleum Engineering Services.

Oil price recovery revives downstream investment

Following on from the two-part survey of the Middle East upstream sector in the February and March issues of *Petroleum Review*, *Mojgan Djamarani* describes recent agreements and projects related to the downstream refining and petrochemicals sector.

The past two to three years has seen a surge in investment in downstream operations in the Middle East. The recent rise in oil prices and increased oil revenues have revived plans by the region's oil producers for the diversification of their economies, especially as Opec production quotas and competition from new oil sources limits their earnings capacities. By expanding their downstream sector, they can also maintain revenues during times of low oil prices. By producing higher value added products and achieving vertical integration to reach closer to the final consumer, the Middle East producers can significantly raise their earnings base and secure new markets.

The Middle East producers are relying on economies of large-scale petrochemical complexes to enhance their competitive advantage. In the current investment drive, large-scale ethylene plants to provide feedstock for the petrochemical industry loom large. The increasing prominence given to the production of natural gas as well as associated gas and condensate in the region has led to an abundance of ethane which in turn gives the region the lowest production cost for the production of ethylene and its derivatives. The small size of the local market necessitates export-led growth. A possible exception to this is Iran, which has a sizeable domestic market of its own.

The re-emergence of the 'tiger' economies from economic stagnation has been a significant factor in the Middle East's downstream investment plans. China and Southeast Asia have been a traditional market for Middle East crude and products because of their geographical accessibility. These countries are forecast to see the largest growth in petroleum consumption through to 2005. As a result most of the expansion in refining capacity is expected to take place in the Middle East and Asia. Through cross-investment and joint ventures, Middle East producers are taking determined steps to secure market share for their refinery exports to avoid a repetition of the 1990s low oil prices as a consequence of an oversupplied market.

Refining capacity in the region is set to increase by almost 1.2mn b/d, an increase of 23%, generated through the construction of new grass root refineries. Most of the new capacity is to come online by 2003/4. But expansion of the refining capacity is also taking place through debottlenecking and the revamping of the existing refineries.

In the petrochemicals sector the picture is somewhat different as many Southeast Asian countries, including India, have become self-sufficient in polyethylene production, leaving only China as the market all must compete for. In Western Europe, another natural market for Middle East producers, they have so far been a low-cost supplier of commodities and moving to higher range products could diminish their comparative feedstock advantage.

Whether the Middle East producers can maintain the current level of investment in the petrochemical sector and whether the return on their investments will be as expected is an open question. Promoting export-led growth will make profitability of their petrochemical industries subject to fluctuations in the world economy, especially as there are no Opec-like organisations and little or no coordination among themselves that can regulate supply.

Bahrain

Bahrain is a major refining centre in the Middle East. Its Sitra refinery with a capacity of 248,900 b/d exports 95% of its products. In 1998, an $800mn modernisation programme of the refinery began, which is to be completed in 2004. The main feature of the programme is the $580mn low sulfur diesel production project to reduce sulfur content of its low sulfur diesel to comply with environmental regulations of most developed economies. Bechtel has been awarded the FEED (front-end engineering and design) package which is to be completed by June 2001.

Other packages in the programme that have already been awarded include Chevron Lumus Globals's 40,000 b/d high conversion hydrocrackers; UOP's 70,000 b/d diesel hydrotreater; Kinetics Technology International's hydrogen plant; Mobile, Akzo Kellogg (MAK) hydrocracker revamp; JGC of Japan's new $27mn keromerox plant; and Alstom's modernisation of instrumentation and control systems at fuel oil and fluid catalytic cracking complexes.

Syria

In Syria there are currently no plans to upgrade the country's two refineries. However, given the increasing volumes of the natural gas feedstock from its existing three gas processing plants and one under construction by Conoco and Elf (see *Petroleum Review*, February 2001), Syria is expanding its fertiliser production.

Plans include construction of a 450,000 t/y nitrogenous complex near Hasaka using gas from the Omar field and the 500,000 t/y triple super phosphate plant near Palmyra (currently under construction by Bechtel and Makad International).

Oman

Oman's refinery at Mina al Fahal is being upgraded to produce unleaded gasoline to comply with GCC (Gulf Co-operation Council) regulations. The EPC (engineering, procurement and construction) package for the 15,000 b/d diesel desulfurisation unit, which is to become operational in 2002, has gone out to tender. The FEED contract for the project, estimated at \$30mn, was carried out by Kellogg Brown and Root. Following last summer's accident at the Al Ahmadi refinery in Kuwait, Oman has also signed a three-year contract with Japan's Petroleum Energy Centre to improve the safety and reliability of the 85,000 b/d refinery.

Japan's JGC was awarded the \$2mn FEED contract for Oman's new grass root refinery at Sohar. The EPC contract is to be awarded by the end of the year. The refinery will be 100% Omani owned and is to supply local and export markets. UOP is the licensor for the fluid catalytic cracker. Borealis and ABB Lumus Global and South Korea's LG Group have been shortlisted for the addition of a \$250mn polypropylene unit which will have a capacity of 340,000 t/y. The unit will initially produce homopolymer.

Oman is also considering the possibility of building a third refinery in the southern city of Salalah.

Construction of two gas pipelines from Fuhad and Saih Nihayda to the industrial cities of Sohar and Salalah (see *Petroleum Review*, February 2001) lie at the centre of Oman's strategy to establish petrochemical industries using gas feedstock. Oman LNG is also considering increasing output by 50% by adding a third train.

Oman rates as the lowest cost LNG producer in the world and contracts for the sale of its current total LNG production of 6.6mn t/y have already been sealed.

Qatar

Qatar is investing large sums in the export of its LNG and petrochemicals as part of its policy of economic diversification. Qatar Petroleum's (former QGPC) projections released in June 2000 aim to increase the share of non-oil revenues to its net cash flow to 50% from the current 30% over the next five years.

The Umm Said refinery is being upgraded to boost capacity to 83,000 b/d from the current 57,500 b/d. A 30,000 b/d condensate refining unit is also being added which will be fed by North and Dukhan fields. Part financing of the \$895mn upgrade project was secured by a deal with Mitsui of Japan. Under a five-year contract Mitsui will purchase 1.4mn t/y of products from the refinery.

The addition of NGL-4 fractionation plant at Mesaieed will increase Qatar's recovery of natural gas liquids from North field phase 1 and Dukhan Arab D recycling plant. Additional quantities of ethane feedstock will supply the Q-Chem plant at Mesaieed and other local demand.

Other projects currently in progress are the construction of Qatar Vinyl Company and Qatar Chemical Complex at a cost of \$1.3bn with the participation of French and US companies.

UAE

UAE's biggest refinery, Ruwais, is undergoing a \$1.2bn expansion and modernisation programme that will increase its capacity to 415,000 b/d from the current 145,000 b/d. This includes a new 135,000 b/d crude distillation unit, a 130,000 b/d fractionation plant and expansion of the residual oil conversion facilities with a 40,000 b/d hydrocracker and a 36,000 b/d visbreaker. The fractionation plant began operations in May 2000 and the completion date for the rest is set for 2003. UAE is the region's largest producer of condensate, which it exports to refineries in Asia. Once the modernisation of Ruwais is complete these exports will end.

The two NGL trains at Ruwais are also being upgraded to add a further 730,000 t/y of mixed gas liquids feed to current production levels of 1.8mn t/y. LPG exports from the new capacity are expected to rise to 4.3mn t/y by 2002.

Ethane from two NGL fractionation trains at Ruwais will provide the feedstock for the Borouge petrochemical plant which is set to become the Middle East's largest plastic production facility. It will boost the region's polyethylene production by some 20%.

However, it is not all good news in UAE as Dubai's 500,000 t/y MTBE (methyl tertiary butyl ether) plant at Jebel Ali industrial zone is facing uncertain future. All the MTBE produced is sold under a long-term contract to Enron, which sells it on the US west coast market. California's decision to phase out MTBE from gasoline by 2002 is threatening the contract with Enron. Dubai will face fierce competition from Iran and Saudi Arabia for new MTBE markets, especially as the Saudi Sabic's 30% subsidy of its domestic butane feedstock for MTBE production puts Dubai at a commercial disadvantage.

Kuwait

Kuwait's plans for the expansion of the downstream sector calls for raising its refining capacity from 850,000 b/d to 950,000 b/d and making products more environmentally friendly. Kuwait Petroleum Company (KPC) is also considering adding a fourth refinery to the country's existing three.

Foster Wheeler International has submitted a pre-feasibility study to KPC for the construction of a new oil refinery in the south with a capacity of 200,000–300,000 b/d at a cost of \$800mn. It will supply high and low sulfur fuel oil as feedstock for power generation.

Foster Wheeler was also appointed as project manager for the reconstruction of the Al Ahmadi refinery in an \$18mn contract. The EPC contract for the works was awarded to Fluor Daniels and SK Engineering and Construction of South Korea. The total cost of repairs is estimated at \$335mn. UOP has been appointed as the licensor for the installation of two new naphtha continuous catalytic reformer units each with a capacity of 18,000 b/d. KPC is also considering setting up a second LNG bottling unit at the refinery to use Qatari gas as feedstock. A new aviation fuel unit is also to be built at Al Ahmadi, while another at Shuaiba refinery is to be expanded.

In petrochemicals, Kuwait has so far confined itself mainly to the production of low value products such as urea, fertilisers as well as ammonia. The Petrochemicals Industries Company is planning to move to production of higher value products.

Iran

Iran has nine refineries with a combined capacity of 1.48mn b/d and plans to boost this capacity to 2mn b/d. Its downstream expansion plans call for construction of new refineries as well as upgrading the existing ones, all with involvement of direct foreign investment.

The upgrade of the existing refineries calls for the construction of a 50,000 b/d hydro desulfurisation unit at Bandar Abbas refinery, as well as the refinery's debottlenecking; construction of isomerisation units at most existing refineries to improve the quality of gasoline; and a feasibility study to furbish all refineries with hydro desulfurisation units. China's Sinopec has been awarded a \$150mn contract for the upgrade of Iran's northern refineries at Tabriz and Tehran to enable them to handle crude from Turkmenistan and

Country	Refinery	Capacity	Cost	Completion	Contractor
Bahrain	New refinery with petrochemical plant	500,000 b/d	$5bn	–	Saudi Petroma Refining and US Hutchinson Group
Yemen	Ras Issa	120,000 b/d	$1.4bn (also includes building a chain of gasoline stations)	–	Monem Khair (Canada)
Oman	near Sohar	75,000 b/d	$750mn	2004	–
Qatar	Condensate refinery at Ras Laffan	80,000 b/d	$540mn	2002	Qatar Petroleum's foreign partners in Qatargas and Rasgas
UAE	at Fujairah	50,000 b/d	$120–150mn	–	Rosneftegazstroi
Iran	at Shah Bahar	225,000 b/d	$3bn	–	–
	Qeshm Island	120,000 b/d	$1.8bn	–	Swiss company Super Petroleum
	Sarakhs	100,000 b/d	–	–	Belgium-based Unit International

Source: MEED, www.oilandgas.com; MENa Petroleum Bulletin; www.eia.doe.gov; MEES; MEM.

Table 1: Planned new grass root refineries

Kazakhstan whose crude has a high mercaptan content. The completion date is set for 2003.

As in Saudi Arabia, Iran is opening up its refining sector to private investment. The country's first privately owned refinery and petrochemical plant is to be built at gas-rich Sarakhs in the northeast on the border with Turkmenistan where a gas processing plant already exists. It will be owned by Bonyad-e Janbazan and Mostazafan, Iran's largest state affiliated economic conglomerate.

Central to Iran's petrochemical sector is the development of two areas in the southwest, Bandar Imam and Assaluyeh based on the South Pars gas field. The National Petrochemical Company's (NPC) third-phase development programme, begun in 2000, consists of five petrochemical projects offered to foreign participation that are to be placed at these ports. The Olefins 8 plant is to be placed at Bandar Imam and the ninth and tenth olefins plants, the fourth methanol plant and the fourth aromatics plant are to be located at Assaluyeh.

Iran controls 0.4% of the world petrochemical market and is aiming to increase its share to 1%. NPC hopes to raise the value of Iranian petrochemical products to $7.5bn by 2005, of which $5bn will be exports. To achieve this it plans to bring online one large project each year between 2000 and 2010. The expansion of the petrochemicals industry will enable Iran to optimise its use of associated gas and to provide an outlet for the natural gas liquids production from the South Pars field. NIOC (National Iranian Oil Company) is also increasing its gas processing facilities to provide feedstock. The two NGL fractionation units currently under construction will feed the 500,000 t/y MTBE plant at Bandar Imam and the 520,000 t/y ethylene cracker being constructed at Assaluyeh.

Saudi Arabia

The increased oil revenues have revived dormant plans for investment in refinery upgrades and capacity expansion to 1.8mn b/d from the current 1.65mn b/d. Under the 1998–2002 five-year plan (FYP) some $5bn is to be spent on enhancing the refining industries. These include the $1.2bn upgrade and expansion of the Ras Tanura refinery. Capacity at the refinery is set to almost double to 540,000 b/d. The project is to be completed by 2003 and is managed by Brown and Root.

The Rabigh refinery is also being upgraded at a cost of $800mn to reduce the production of low value heavy products. The upgrade will add a 172,000 b/d vacuum distillation unit, a 55,000 b/d continuous catalytic reformer, a 100,000 b/d hydrocracker, a 63,000 b/d visbreaker and an 89,000 b/d naphtha splitter. Foster Wheeler is the project manager.

The Jubail refinery, a 50/50 joint venture with Shell, has a $70mn EPC contract with Foster Wheeler Italiana for its expansion. The Riyadh, Abqaiq, Yanbu and Jeddah refineries are also seeing their instrumentation and control systems being modernised.

Saudi Arabia has the most established petrochemical industry in the region. It plans to increase the number of products that use petroleum derivatives to be manufactured domestically. This would enable it to export higher value added products while at the same time maintain its export of basic chemicals. In the period 2000–2004 Sabic's target is to achieve a 5–10% annual growth in production in chemicals, fertilisers and metals. Its longer-term target is to raise production to 48mn t/y by 2010.

Increased natural gas feedstock for the petrochemical sector is being supplied by Aramco through the expansion of its gas processing facilities which include a $385mn new NGL recovery unit at the Berry gas processing plant to be built by mid-2002 by AmecBabcock King Wilkinson of the UK (see *Petroleum Review*, February 2001).

Sabic is already a leading supplier of a wide range of polymers and the availability of low density polyethylene at Petrokemya will further boost its presence in the polymer market. The company also holds 13% of the world MTBE market and is the main MTBE exporter to the US.

Country	Project	Production	Cost	Status
Syria	Triple super phosphate plant	500,000 t/y	–	Under construction by Bechtel and Makad International.
Oman	Urea plant near Sur	1.65mn t/y of granulated urea and 248,000 t/y of ammonia	$969mn	Joint venture of Oman Oil Company and Indian Farmers Fertilizer Cooperative and Kirshak Baharati Cooperative Ltd. The Indian partners will each invest $80mn and the Oman Oil Company $160mn.
	Ethylene and polyethylene plant near Sohar	450,000 t/y polyethylene; 450,000 t/y ethylene	$1.3bn	Undecided since BP withdrawal.
	Methanol plant for Sohar Port	Initial output of 5,000 t/d	$426mn	Joint venture of Germany's Ferrostaal and local investment group Omar Zawawi Establishment. Scheduled to come onstream 1Q2005
Qatar	Q-Chem at Mesaieed	500,000 t/y of ethylene and 467,000 t/y of polyethylene, including high density and linear low density polyethylene and 47,000 t/y of hexane 1	$1.1bn	Joint venture of Phillips Petroleum Company (49%) and Qatar Petroleum (51%). To begin exports in 2002. *Sub-contracts*: Consolidated Contractors International – $60mn sub-contract for onshore civil, mechanical, electrical and instrumentation work on the polyethylene plant and offsite. Industrial Control of Honeywell – $10mn to provide automation and control systems for the project.
	Qafco – Qatar Fertilizer Company phase 4 expansion	Increase ammonia production from 3,800 t/y to 6,000 t/y and urea production from 4,800 t/y to 7,000–8,000 t/y	$500m–$700 mn	–
	Ras Laffan LNG Company	To double capacity to 14.9mn t/y. Addition of two trains with 4mn tonnes capacity each.	$2bn	The first of the new trains to come onstream in 2004 and the second shortly thereafter. Contracts to be awarded in April 2001. FEED contract for the downstream works was awarded to Japan's Chiyoda, for the mid-stream Italy's Saipem and for upstream J Ray McDermott Engineering.
	Upgrade of control systems at Mesaieed NGL plants 1 & 2	–	–	Technip awarded the contract. Start-up date: November 2001.
	Fourth NGL fractionation plant at Mesaieed	115,000 t/d – ethane	$400mn	Under construction by Snamprogetti and Hyundai Engineering and Construction.
	Methanol project	3mn t/y from three production trains	$1bn	Qatar Petroleum (51%), Methanex Corp (49%).
	Gas-to-liquids project	30,000 b/d of middle distillates	$500–700mn	Joint venture of Qatar Petroleum (51%) and Sasol (49%).
	Toluene diisolyanate (TDI) plant	100,000 t/y of polyurethane foams	$250mn	Joint venture of Qatar Petroleum and Italy's Enichem.
UAE	Borouge Petrochemical plant	600,000 t/y ethylene cracker unit, two 225,000 t/y polyethylene units	$1.2bn	Joint venture of Adnoc (60%) and Norwegian–Finnish company Borealis (40%). To come onstream in 2001/2.
Kuwait	Revamp and expansion of ammonia production at Shuaiba fertliser complex	To increase ammonia production from 800 to 880 t/d	$30–40mn	Halder Topsoe of Denmark appointed as engineering consultants.
	Upgrade of Shuaiba fertiliser complex	Construction of 2,000 t/d methanol plant	$130mn	Lurgi of Germany appointed as licensor for the plant.
	Construction of storage tank and facilities at Shuaiba propylene production plant	5,000 tonne storage tank	$32.3mn	Out to tender

Table 2: Current petrochemicals projects

Country	Project	Production	Cost	Status
Iran	Olefins 7 at Bandar Imam	1.1mn t/y – ethylene, 200,000 t/y – propylene	$350mn	German company Linde awarded the contract. Completion date 2003.
	Aromatics 4 complex	3.19mn t/y main and by-products	$94mn	Being built by Toyo Engineering Corp and Iran's Sazeh Engineering Co.
	Olefins plant at Assaluyeh	520,000 t/y ethylene cracker, 150,000 t/y propylene capacity	euro 180mn	Linde is the contractor. To come onstream in mid-2002.
	LPG projects – NGL 900 and NGL 1200	400,000 t/y combined	–	To come onstream early 2002.
	Methanol plant	1.6mn t/y	$145mn	Joint venture of Lurgi Oel-Gas-Chemie of Germany and Iran's state petrochemical firm Zagros. Completion date 2003.
	Methanol plant at Bandar Imam	1mn t/y	–	Snamprogetti is the contractor.
	Polyethylene plant at Bandar Imam (Olefins 6)	300,000 t/y of linear low density polyethylene and high density polyethylene	$85mn	Joint venture of Amir Kabir Petroleum Co (40%) and Balli Petrochemicals of UK (60%). The plant will be constructed by Technip. To come onstream in 2003.
	Gas liquefaction plant at Gachsaran	132,000 b/d of liquid gas	$120mn	To become operational in 2002.
	Paraxylene plant at Bandar Imam	180,000 t/y	$82mn + Rls 165bn	Came onstream in January 2001
	Olefins 9 ethane cracker at Assaluyeh	1mn t/y	$170mn	Technip and local Nargan Consulting Engineers to carry out work to be completed by 2003.
	Olefins 9 complex gas separation plant	3mn cm/h	$162mn	Being built by Linde. To be completed in 2003.
	Polyethylene plant at Bandar Imam (Olefins 6)	300,000 t/y of low density polyethylene	–	EPC contract to be awarded this spring. A joint venture of NPC (45%) and Elenac (55%). Elenac is a joint venture of BASF and Shell. Start-up date: end of 2003.
	Fertiliser complex at Bandar Assaluyeh	2,050 t/d ammonia; 3,250 t/d urea	–	Out to tender.
	Ethane recovery plant at Bandar Imam	150,000 t/y ethane and 50,000 t/y propane	–	Design and engineering contract put to tender by Bandar Imam Petrochemical Company in February. Nargan carried out the feasibility study.
	Acetic acid project in Bandar Imam	150,000 t/y	–	Documentation issued in February.
	High density polyethylene plant at Bandar Imam (Olefins 7)	300,000 t/y	$85mn	Joint venture of Krupp Uhde and Iran's Sazeh Engineering Company and Marun Petrochemical Company. To come onstream in 2003.
	Methanol plant on Kharg Island	660,000 t/y	$206mn	Built by Lurgi. Came onstream in March 2000. Feeds the MTBE plant at Bandar Imam.
	Three polypropylene, linear light polyethylene and ethylene glycol plants at Assaluyeh (Olefins 10)	300,000 t/y of polypropylene and LLP each and 400,000 t/y of ethylene glycol	$330mn	To be completed in late 2003. Technimont of Italy is the contractor with Nargan Consulting Engineers on the first two plants and with PIDEC on the EG plant. The basic engineering package is sub-contracted to Mitsui and Shell will provide the technology.

Table 2: Current petrochemicals projects

Country	Project	Production	Cost	Status
	High density polyethylene plant at Assaluyeh	300,000 t/y	$120mn	Krupp Uhde and Sazeh Engineering Consultants are the contractors.
Saudi Arabia	New olefins complex at Jubail United Petrochemical Complex	800,000 t/y – ethylene, 400,000 t/y HDPE & LLDPE, 460,000 t/y of ethylene glycol, 100,000 t/y alpha olefins polyethylene	$2bn	Bidding for the lump sum turnkey project to begin in mid 2001. Completion date set for late 2004.
	Bi-modal polyethylene complex at Petrokemya	400,000 t/y	$200mn	Lump sum turnkey contract to be awarded by the end of 2001.
	Debottlenecking at Arabian Industrial Fibers Company	Polyester production to increase from 190,000 t/y to 200,000 t/y	–	Installation of a 250,000 t/y polyethylene terephthalate unit also being considered.
	Installation of a second polypropylene unit at Saudi European Petrochemical Company (Ibn Zahr)	320,000 t/y	–	EPCM contractor is the US Parsons Corporation. To come onstream in 1Q2001.
	Debottlenecking of ammonia unit at Al-Jubail Fertilizer Company (Samad)	Raising capacity from 1,000 t/d to 1,200 t/d	$15mn	Contract awarded to Swiss Ammonia Casale. Additional capacity to come onstream by late 2001.
	Construction of propane dehydrogenation and polypropylene plant at Jubail.	450,000 t/y PDH and 450,000 t/y PP	$310–320mn	ABB Lumus Global and Targor (a joint venture of BASf and Hoechst) will supply the technology. Project manager Raytheon Engineering & Constructors. Completion date: 2002.
	Saudi International Petrochemical Company (SIPC) plant in Jubail which will include hi-tech methanol plant producing maleic anhydride and butanediol, a vinyl acetate monomer, a common utilities plant, methanol plant and carbon monoxide plant.	300,000 t/y acetic acid, 850,000 t/y methanol, 140,000 t/y carbon monoxide.	$800mn	Will become operational by the end of 2003. Fluor Daniels is the project manager. Jacobs Engineering Ltd to provide process technology for the methanol and carbon monoxide plants. Du Pont Company has been appointed technology supplier for the vinyl acetate monomer, US Huntsman for the maleic anhydride unit and Kvaerner for the butanediol unit.
	Two petrochemical plants at Jubail	120,000 t/y normal paraffin and 100,000 t/y linear alkyl benzene	$287mn ($152mn and $135mn respectively)	Joint venture of Saudi Offset Ltd Partnership and Tamilnadu Petroproducts (subsidiary of India's Southern Petrochemicals Industries Corporation). First production scheduled for 2003.
	Petrochemical complex at Jubail	1mn t/y ethylene, 460,000 t/y ethylene glycol, 400,000 t/y HDPE and 100,000 t/y linear alpha olefins	–	Fluor Daniels Arabia appointed project manager. To come onstream in 2004.
	New polyethylene plant at Petrokemya	400,000 t/y LLDPE and HDPE	Estimated at under $200mn	To be built by Toyo Engineering Corporation in a lump sum turnkey contract. Union Carbide Corporation is to supply its Unipol process technology for the plant. To come onstream in mid-2002.
	National Petrochemical Industrialisation polypropylene plant.	450,000 t/y	$533mn	To be completed in early 2003.
	Debottlenecking ammonia plant at Ibn Al Baytar (National Fertilizer Company)	To raise design capacity by 83,000 t/y to 583,000 t/y	–	EPC contract awarded to Toyo Engineering Corporation. Due for completion in 1Q2002.

Source: LPG World; MENA Petroleum Bulletin, MEED, MEES, MEM, Petroleum Economist, www.oilandgas.com, Sabic website, Middle East, Oil Review Middle East, various websites

Table 2: Current petrochemicals projects

Electricity deregulation – a Titanic disaster

Electricity deregulation, as implemented in California and to a much lesser extent in Alberta, has proved a monumental disaster. *Gordon Cope* examines how it went so wrong and the lessons to be drawn.

California's Diablo Canyon nuclear power plant curtailed production by 80% when a severe winter storm struck in January. Photos courtesy of Jim Zimmerlin, Diablo Canyon.

It has all the elements of a classic Hollywood disaster movie: a great ship of state surges ahead on the seas of the global economy; suddenly, it strikes an unseen hazard; the captain and crew valiantly struggle to save the passengers before the vessel sinks beneath a wave of irresistible forces.

The ship, of course, is the state of California. The passengers are the hapless citizens, and the unseen hazard is electricity deregulation. While giant utility companies Pacific Gas & Electric (PG&E) and Southern California Edison flounder beneath an estimated $12bn of unrecoverable debt, Governor Gray Davis, ostensibly at the helm of this wreck, throws one concrete life preserver after another into the turbulent waters.

'California is becoming the poster child for deregulation gone wrong,' says Michael Zenker, Director of Western Energy at Cambridge Energy Research Associates (CERA), an independent research firm based in Cambridge, Massachusetts.

Yet, when deregulation of the electrical sector was first put forward in California in the mid-1990s, the initiative was seen as a win–win situation for producers, consumers and regulators. How did this unsinkable combination founder?

When California first began considering deregulation, proponents of the scheme looked to the success of the UK. There, the state system was broken into four major, separate components: generation, transmission, distribution and retail supply. Generation facilities were sold off; transmission and distribution remained under regulation; and retail supply was opened to qualified competitors. Full competition came to the UK domestic electricity market in May 1999.

Although the UK system had a generous amount of reserve capacity at the time of deregulation, suppliers were given a special top-up to assure the continued creation of reserve capacity. The new system resulted in sufficient return on investment to convince over 50 companies to participate, and sufficient supplies to keep prices in competition mode. According to Ofgem – the UK's gas and electricity industry watchdog – more than 5mn people have switched supplier to date, and switching is continuing at the rate of around 370,000 customers each month.

Charting a course

In California, the system was slightly different. Consumers relied on three main investor-owned utilities to supply, transmit and distribute the majority of electricity: San Diego Gas & Electric, PG&E, and Southern California Edison (some urban areas, such as Los Angeles, also had their own municipal utilities).

Although total power generation capability within the state had remained stable for several years at 45,000 MW, insufficient generation capacity was not seen as a stumbling block. Peak loads had only risen to 33,000 MW of electricity (a megawatt is enough to power 1,000 homes) and interstate transmission lines allowed access to another 8,000 MW if needed.

'The idea was to first introduce competition to the wholesale market,' says Joseph Doucet, a Professor of Regulatory Economics at the University of Alberta. 'The top three producers – Southern California Edison, PG&E and San Diego Gas & Electric – therefore had to sell their generation assets.'

An Independent System Operator was set up to oversee transmission, as well as the California Power Exchange marketplace, where the utilities were to purchase all of their electricity supplies. In addition, the utilities were not allowed to purchase long-term contracts; they could only buy electricity on a next-day basis. 'The regulators were afraid they would shaft smaller customers,' says Doucet.

Finally, the retail price was capped to 2002. 'The logic was that until you introduced enough players into generation, you didn't want existing players to raise retail prices,' states Doucet. No top-up measure, a key element to ensuring healthy generation reserves in the UK, was ever seriously considered.

Competitive rates

In 1996, California legislated competition in the wholesale electricity market, a price drop for consumers of 10%, and the creation of a state-controlled market where utilities could buy power wholesale. The plan was implemented on 31 March 1998. In general, consumers were pleased because there would be no price increase for four years. The large utilities accepted the plan because they hoped to profit from the difference between the declining wholesale price and the stable consumer price. Lawmakers were happy because they felt they had maintained sufficient oversight to contain the utilities.

In Canada, the province of Alberta was the first to seriously pursue an electricity deregulation policy. Like California, there were three large investor-owned utilities that owned generators, transmission and distribution. They each had a franchise (monopoly) service for a geographical area. Peak loads, which were approaching 6,000 MW, were still well within the margin of 7,500 MW of provincial generation capacity. Power could also be imported from British Columbia, which has a large excess hydroelectric capacity.

After several years of discussion, Alberta enacted deregulation legislation in January 1996. 'Essentially, they broke the old utilities into generation, transmission and distribution companies, maintains Duane Reid-Carlson, Vice President of Optimum Energy Management, an energy consultancy. 'The government was not willing to force divestment, however. TransAlta (a major utility) still owns generation and transmission facilities, but sold their distribution end.'

Because there were still only three generation companies (and one, TransAlta, controlled 60% of capacity), there was no true competition, states Reid-Carlson. 'They needed to add more buyers and sellers.' On 1 January 2001 there was one final step, breaking retail services out of distribution wire services. Competition was to be at the consumer level.

The storm gathers

Even before the ink was dry on California's legislation, experts began to notice flaws in the deal. 'California has severe environmental constraints because of its large population and geography,' says Doucet. 'Pollution can get trapped in basins, like Los Angeles. Large industrial emitters like power generators have to have emission credits.' Thanks to the straight-jacket of environmental law, only 700 MW of power had been approved in the state over the last several years.

Generator fuel prices were also rising dramatically. Also, over the last year, demand had pushed the price of natural gas up from under \$3/GJ to \$9 for winter delivery. Costs for producing electricity on gas turbine generators nearly tripled.

Aggravating the situation were several years of low precipitation in the Pacific Northwest, which had left large hydroelectric suppliers like the Bonneville Power Administration, of Portland Oregon (which operates massive federal hydropower dams in the region), with seriously depleted reservoirs.

Under such conditions, wholesale prices rose consistently, but California utilities were unable to pass those cost increases on to their customers. Low retail prices insulated consumers from the pressures of conservation and more efficient use of electricity. Capacity increased at a snail's pace, and a growing imbalance of demand and supply spurred wholesale prices on to an upward spiral.

The first warning signs that something was seriously amiss occurred in mid-2000. Demand for air-conditioning pushed peak loads to within 2% of total capacity. Generating plants were run to the limit, causing the aging infrastructure to fray. By the onset of winter, several major plants had to be closed for repairs.

In Alberta, regulators were aware that many of the same problems being experienced in California also existed in their province. While pollution laws were not as strict (and most of the power plants ran on coal, not natural gas), there had been few new base-load plants built in the last decade, even though the growth in the economy had dramatically increased

demand. 'You need a minimum of 5% to 7% operating reserve in the system to handle generator downtime,' comments Reid-Carlson. 'The total operating reserve had dipped below that.'

Nevertheless, regulators went full steam ahead, holding an auction in the fall of 2000. 'They put 6,000 MW up for sale in the form of 20-year power purchase agreements (PPAs),' says Reid-Carlson. 'The idea was for marketers to buy these PPAs then sell them into the retail marketplace.'

Only about 4,000 of the 6,500 MW sold, for about C$1bn. Regulators made some major changes and had a second auction in late December, but it was not successful, with about another C$1bn sold. 'This was substantially less than what people thought it was worth, and there was a lot of generation capacity left hanging out there,' says Reid-Carlson.

The unthinkable happens

When a winter storm hit the California coast in January, several plants were forced to shut down, and 15,000 MW of generation fell out of service. Prices on the California Power Exchange, where the states three investor-owned utilities bought most of their power, began to rise dramatically, hitting spot peaks of $3,000/MWh. Retail rates for residential consumers had been fixed at $100/MWh, and the dramatic increase put an intolerable financial squeeze on utilities. By January 2001, PG&E and Edison were short almost $12bn, and on the verge of bankruptcy. The California Public Utilities Commission granted PG&E and Edison an electricity rate increase of 10%, far below what it needed. Power generators became concerned that the utilities could no longer afford to pay them, and out-of-state sources became scarce.

By late January, California had declared its first state of emergency. Rolling blackouts hit 500,000 consumers in north and central California around San Francisco. As homes and businesses plunged into the dark, some state legislators proposed that California expropriate power plants. In addition, Governor Gray Davis asked generators to sell power to PG&E and Edison under three-year contracts for $50 to $55/MWh (so far, the lowest available rates being offered are in the $80 range).

In Alberta, electricity rates jumped from C$50/MWh to over C$200. The provincial government announced temporary price caps and rebates to hold increases to the C$100 range, but many high-energy users, such as foundries, began to lay off staff. 'The biggest problem right now is that the government is facing an upcoming election, and they're making rash, last-minute changes that are creating more uncertainty,' says Reid-Carlson. 'They're trying to put band-aids on things that have long been problems.'

Man the pumps

In the short term, California homes are scrambling to reduce unnecessary consumption, and early reports indicate that peak usage has dropped by 1,000 MW, or approximately 3%. But much of the demand, especially industrial use, is not easy to change. 'It takes 12 months or longer to shift load off-peak, to build different plants, etc,' comments Reid-Carlson.

In Alberta, many industrial facilities with high energy input costs are considering closure. 'We've looked at pure economic price thresholds – what price it takes to get production of a commodity off the market, and we see that there are several electricity intensive industries where they are out of business at $100/MWh,' says Reid-Carlson. 'Petrochemicals – fertiliser, methanol, sodium chlorate – they're all exposed. They can subsidise for a short time, but nobody likes to see 12 months of red ink. Our feeling is that it will improve, but not quick enough for some companies.'

Some industrial users are making power on their own. Capstone Turbines, based in California, manufactures microturbines capable of producing 30 kW of electricity (enough to power a small plant) (see *Petroleum Review*, January 2001). 'We sold 211 units in 1999, and we're anticipating four times that in 2000,' says Keith Field, spokesman for the firm. 'It's fair to say we'll continue growth at a similar rate this year [2001].'

In Alberta, some small businesses and homes are switching to coal. The province possesses an abundance of inexpensive, low-sulfur deposits and several manufacturers are offering automated units that can heat a greenhouse for as little as $500 per year. 'The phone has been ringing off the hook since August,' reports D'Arcy Belanger, a spokesman for Nova Metal Tech, a builder of coal furnaces.

In the meantime, electricity generators are announcing plans for new facilities in California. Duke Energy alone has 1,300 MW of proposed projects before state regulators. But even with fast-tracking of permits, it will be several years before a sufficient cushion of reserve capacity is in place. 'It will be a troubling year for California,' says Doucet. 'It won't necessarily be worse this summer, there will be fewer units down, but things won't necessarily be better for the next year or 18 months'.

California's legislation will also need a complete overhaul. 'They need to introduce long-term contracts to give some price stability on the supply and demand sides,' says Doucet. 'They need to improve the financial situation of the large retailers – they can't let them go bankrupt. They need to ensure commitments to out-of-state suppliers. Finally, they have to make an assurance that investors will be able to make money.'

In Alberta, Enmax and Fording Coal are entering into talks to build a 400-MW power plant near a 125mn tonne deposit of low-sulfur coal (coal-fired plants are more expensive to build, but cheaper to operate because of lower fuel costs), and Virginia-based AES Corporation is proposing a $450mn, 525-MW gas-fired plant east of Calgary. 'We're playing catch-up now, and it won't be until 2002 or 2003 before we move back into the comfort zone,' says Reid-Carlson.

For those jurisdictions that are contemplating deregulation, such as Nevada, Arkansas, Oklahoma and Ontario, Allan Warrack, a Professor of Business at the University of Alberta and a former Utilities Minister for the Alberta Government, has some trenchant advice. 'Deregulation policy needs to be worked out in a detailed and reliable way so that people can be confident making investments on it,' he warns. 'You don't convert coal or natural gas into electricity, you convert financing into electricity. Uncertainty and risk kills investments.'

New challenges facing geoscience knowledge

After nearly three years of hardship, companies operating in oil and gas exploration and production, as well as oilfield service companies, are now entering a period that signals a great change. This is not a case of just 'one more cycle' – where oil prices recover and the industry continues to conduct 'business as usual' – this time, it is a more fundamental shift. The industry is emerging with new business models and the oil and gas companies, together with the oilfield service companies, are redefining their roles and their coexistence. *Eldad Weiss,* Chairman and CEO, Paradigm Geophysical, reports.

Although the $10/b price shocker signalled the beginning of the oil price crisis, continued concerns about oil price volatility and the consequent need for business discipline to mitigate this volatility may not be the only reason behind this fundamental shift in company management and practice. There are a number of other reasons, including a deep realisation that the significant monies invested in exploration at new frontiers are hardly sufficient to maintain the reserves at their current levels. This realisation is forcing oil companies to focus on extracting the most value out of their existing assets. A second reason is the global business climate spurring consolidations with both significant M&A (mergers and acquisitions) activity, and sales or exchanges of producing and dormant oil-property assets. This dictates the need to manage in 'constant change mode.' Perhaps even more critical on a day-to-day basis, the industry is having to grapple with a shortage of 'knowledge staff' while maintaining, and even increasing, their levels of investment and output. All these factors point to the significant structural changes now ongoing in the industry.

While in the past geoscientists were very much focused on identifying new exploration targets, the latest advances in technology and workflow design are opening up exciting opportunities to provide significant added-value to the development and production stages of the oil field life cycle. For example, the drilling process can now be fully integrated with the geoscientist's subsurface model, permitting the requirements of the drillers to be visualised and analysed by applying our geoscience knowledge. This is expected to achieve significant savings in every major drilling programme. Over the lifetime of a field enhanced oilfield production can now be achieved through the use of advanced geoscience analysis tools integrated with production data. Here, too, significant production efficiencies are expected.

Geoscience knowledge companies such as Paradigm Geophysical have a considerable role to play in these changing times – providing, through a combination of products and services, the technical information solution infrastructure needed to support the change process and the productivity goals. These solutions help oil and gas exploration and production companies unlock the most value from their assets by leveraging their large investment in a wide array of oilfield measurements – seismic, well logs, production data – using streamlined and highly productive new workflows.

The next generation in computing and geoscience applications technologies now enables the applications and workflows needed to integrate all the information available on the oil field. This, in turn, has led to better-qualified new exploration targets, optimised well planning and drilling design, and enhanced reservoir production.

The following paragraphs review how the next generation of geoscience solutions supports the changes in the industry within three key workflows – the prospect evaluation workflow; the well planning and drilling workflow; and the reservoir study workflow (see **Figure 1**).

Prospect evaluation workflow

For many years the geoscience software providers were focusing on the basic exploration workflow or the 'prospect evaluation workflow,' including seismic data acquisition and processing, interpretation and drilling. The objective of these workflows is to reach a 'Go/No Go' decision on exploration drilling as quickly as possible by integrating the acquisition, processing and interpretation phases.

Seismic data acquisition was done most of the time as proprietary surveys on demand, with an increased focus on onboard processing in a bid to reduce lapsed time and data volumes. Well-log information, if available, was integrated in the process only at the interpretation phase. There were many people and companies dedicated just to this process.

The seismic data acquisition companies were offering integrated seismic data processing services both onboard their seismic vessels and at their data processing centres. Exploration divisions within oil companies were ready to interpret the data as soon as the processed information arrived from the acquisition company and to generate as many prospect maps as fast as possible using advances in 3D interpretation technology such as 3D auto-picking utilities.

A lot of emphasis, time and money was invested in corporate-wide, monolithic data management systems to feed the interpretation process with the relevant information. Based on the resulting maps, the geoscientists made their recommendation for drilling locations to management. This workflow remains, of course, the key workflow used today for prospect evaluation.

The roll of the geoscientist working in the oil and gas companies had been broadly two-fold: (1) quality control of the seismic contract work and the analysis and interpretation of the seismic data, with prospect evaluation, and (2) producing for management a list of recommended drilling targets.

This workflow had been changing, as in recent years the seismic acquisition companies had been developing their own seismic data libraries for the oil companies to choose from. As a part of its services the data brokers would provide data that is processed, or at least partly processed, and in some cases they would include partial interpretation to indicate potential prospects. From the oil company perspective their involvement in the design, execution and quality control of the seismic survey had been reduced, moving the responsibility for the quality of the data acquisition and processing from the customer to the vendor.

The recent staff shortages being seen in the industry are now resulting in the outsourcing of data interpretation, with the role of the staff geoscientist moving to that of quality control of these subcontractors, and as the final prospect evaluators and decision makers.

At the same time, interpretation workflows have become more productive, as solutions provide for better visualisation, permitting a move from line-based to volume-based interpretation.

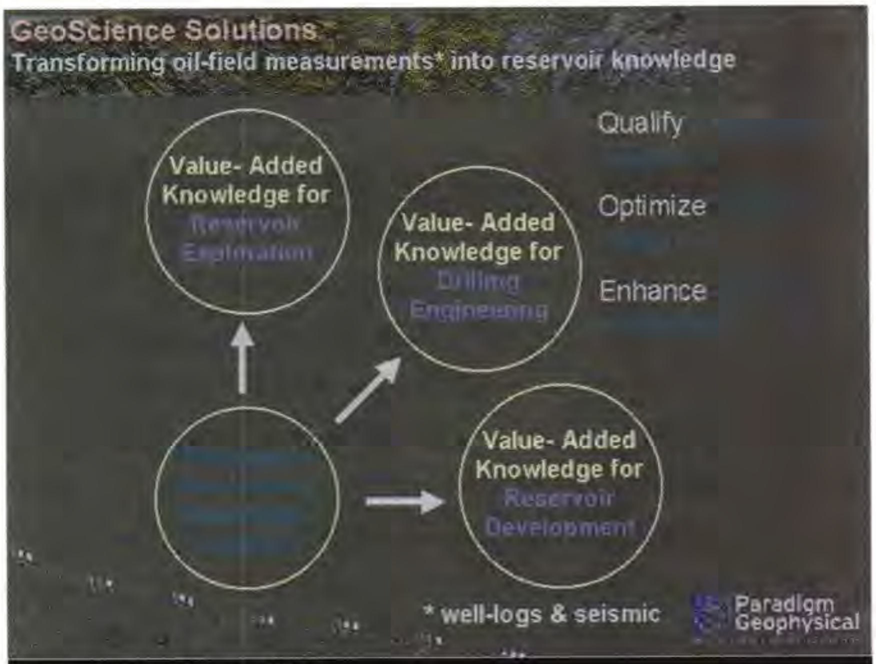

Figure 1: Three key workflows

Reservoir analysis workflow

The industry had been shifting resources to the development of the reservoir. The process of understanding the reservoir requires much-refined workflows in order to extract the most out of the data available. Here, the integration effort is focused on all the data available on the field and all data made available throughout the lifecycle of the field.

The exploration workflow was the central workflow, around which oil companies and oilfield companies have been organised during the last few years. The new demand for better understanding of the reservoir is setting a new challenge to the oil companies as well as to the oilfield service companies.

The challenges are technical as well as organisational. A reservoir study project requires the availability of all the relevant prospect information throughout the history of the field in a strongly project-oriented data management scheme. The information should be available to all the applications involved in the management and analysis of such a project. We need to analyse pre-production and post-production field information, such as seismic and well data, as well as production history information. We also need to integrate seismic data analysis workflows, formation evaluation and reservoir model building workflows, petrophysical and rock physics workflows and reservoir characterisation and simulation workflows. The technical challenge is to create the systems and technologies that will streamline and optimise this sophisticated and complex workflow.

The logistical and organisational challenge is to create the units and the processes within the oil companies, as well as within the oilfield service companies, to accommodate these requirements. With today's limited geoscience knowledge staff within the oil companies themselves, the knowledge-oriented oilfield service companies are gearing up to provide such services on turnkey basis.

Project-based data management schemes, and advances in data interoperability, facilitate easier access to data analysed by various vendors' software and of different vintages and formats.

While organising and integrating the tools is a technological challenge that company's like Paradigm are meeting, reorganising the human interactions is perhaps a bigger challenge. This is the essence of change management. The new tools will permit the asset teams to work differently and will permit a higher level of professional interaction among the various geoscience and engineering disciplines.

Well design and drilling workflow

Another field that is expected to hold great promise for geoscience-based information solutions is for well design and drilling engineering.

With the advances in geoscience knowledge we can integrate the seismic data analysis workflow, advanced volume based visualisation technology and the well design parameters, to optimise the drilling engineering process using the available information from field measurement. Establishing predicted pore pressures for optimised well design, interactively locating the optimal well path and using real-time monitoring while drilling allows us to achieve modelling-while-drilling, as well as the interactive redesign and re-engineering of the well path. All of this is now feasible and will save both significant time and expense in the very costly drilling process.

New company role

Knowledge, not oil, is the real barrier for assets growth in this new age for oil and gas companies. The new, sophisticated processes needed for reservoir studies and drilling optimisation workflows call for specialised software technology, as well as a new business solution offering. At Paradigm we focus on an integrated solution offering, providing the software as well as the product-driven services complementing the software, in order to provide easier access to such workflows to the whole industry.

The oil company of the future may wish to be an overseer in the reservoir study process, while leaving the specialised work to knowledge-providers such as Paradigm. Indeed, the future holds the promise that we can execute an ever-increasing role in the E&P knowledge-based analysis process.

Free market for European gas in the pipeline

The Interconnector gas pipeline is far more than just a physical pipeline between the UK and the Continent. It provides both the instrument and the opportunity to develop a free market for gas in Europe. Already, the total amount of gas traded far exceeds that physically transported – the Interconnector has effectively created a market. *Linda Scott* of EDS* explains the development of the pipeline connection, the impact of linking gas price to oil price, and the potential market opportunities proffered by the Internet.

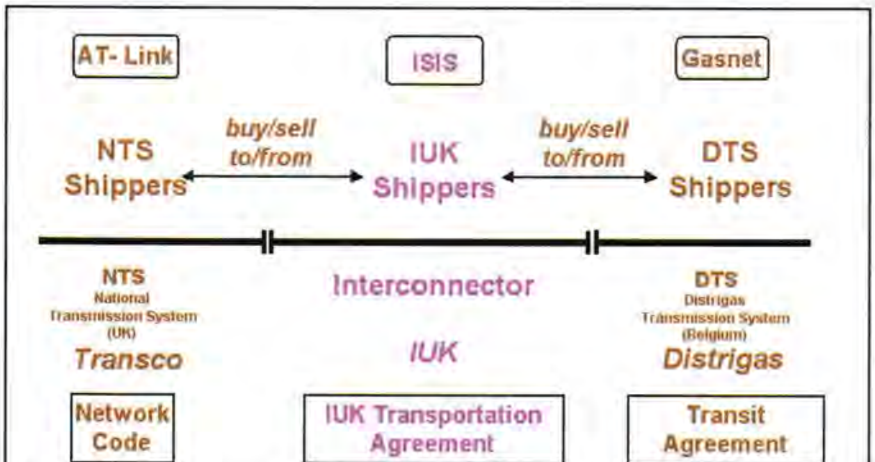

Figure 1: The transportation chain

Success in today's competitive gas supply world is totally dependent on the flow of accurate, live information. Players are no longer local or even national – they are international and becoming global. Nearly 10,000 miles of new mainline gas pipelines are being constructed each year, crossing international and cultural borders. Short-term demand for gas changes, quite literally, with the weather and to add to the challenge, gas storage capacity is very limited. So, accurate judgement of the market is not for the faint-hearted. The winners will be the companies best able to use information to identify and respond rapidly when market opportunities change.

EDS, as Interconnector UK Ltd's information technology partner, is responsible for the software and hardware that provides the information flows crucial to shippers using the Interconnector gas pipeline, linking the gas grids of the UK and Belgium. The pipeline, which became operational in October 1998, is one of Europe's most important energy infrastructure developments in recent years. It has had a profound impact because it is a bi-directional link between two markets – in the words of Cambridge Energy Research Associates (CERA), the Interconnector has become 'embedded in the psychology of the gas market place.'

A market has quickly grown up to trade gas in both directions across the Interconnector (see **Figure 1**). The total traded far exceeds the volume physically transported, which is the calculated difference between the flow nominated in each direction. The requirement for fast-flowing information, which is secure and reliable, continues to grow with the developing gas market.

European gas market

A free European gas market, without ties to oil prices, is looking increasingly appropriate to meet today's market needs. Gas and oil are two commodities with very different outlooks in the 21st century. Gas was once the embarrassing accompaniment to a good oil flow –

best flared and forgotten. Not any more. Pipelines and new technologies, such as gas-to-liquids, are unlocking the value of gas as a cleaner and plentiful energy source.

In the UK, the price of gas, as with any commodity, has in recent years, been set by the balance between supply and demand. However, in Europe there is a tradition of setting a quarterly gas price to reflect oil prices. This is for two reasons, firstly, because oil and gas were seen as competing fuels and, secondly, when gas was not a traded commodity it was possible to hedge against gas price movements in the traded oil markets. This link affects the market and, after a period of high oil prices such as we have recently experienced, the price of gas is also raised.

At the beginning of 1999, wholesale spot gas prices in the UK were around 12 p/therm – a very attractive price for Continental buyers facing prices of over 20 p/therm. UK gas shippers and suppliers, faced with the choice of selling gas in the UK at 12 p/therm or on the Continent at over 20 p/therm, made an understandable commercial decision. The impact of this was twofold – the UK supply/demand position tightened and the price of the deal became the marker for the UK spot market.

One of the objectives of the European Commission in encouraging a free market in gas is to reduce gas prices along with all energy prices in order to compete more effectively in the global marketplace. The pegging of the gas price to oil undermines this and the impact is now being felt, with the UK seeing wholesale gas prices double over the last year. The UK's gas price is likely to reflect fluctuations in the oil price until the European link with oil is broken.

The key question in many people's minds is whether the price of gas will fall again. In reality, the current price of gas is not high when compared with prices going back over the past 20 years. Gas prices have fallen in real terms since the mid-1980s and current gas prices are still some way below what they were then. This has contributed to a lack of investment in new supplies, further tightening the supply/demand balance. However, gas consumers have become accustomed to lower gas prices and are unhappy about the recent rises. Some industry analysts believe that gas prices are approaching their peak and the most likely outcome is that prices will fall over the next few years.

Meeting growing demand

Demand for gas is growing (see **Figure 2**). By 2010 it is likely that gas will be the source of 50% of all non-renewable energy. In Europe, electricity generation is largely responsible for driving this increase in demand, with projections that 40% of electricity generation will be fuelled by gas in 2010, compared with about 15% today. Part of the attraction of gas is that, as a relatively 'green' fuel, it helps to limit the emission of pollution in line with international agreements such as the Kyoto Protocol.

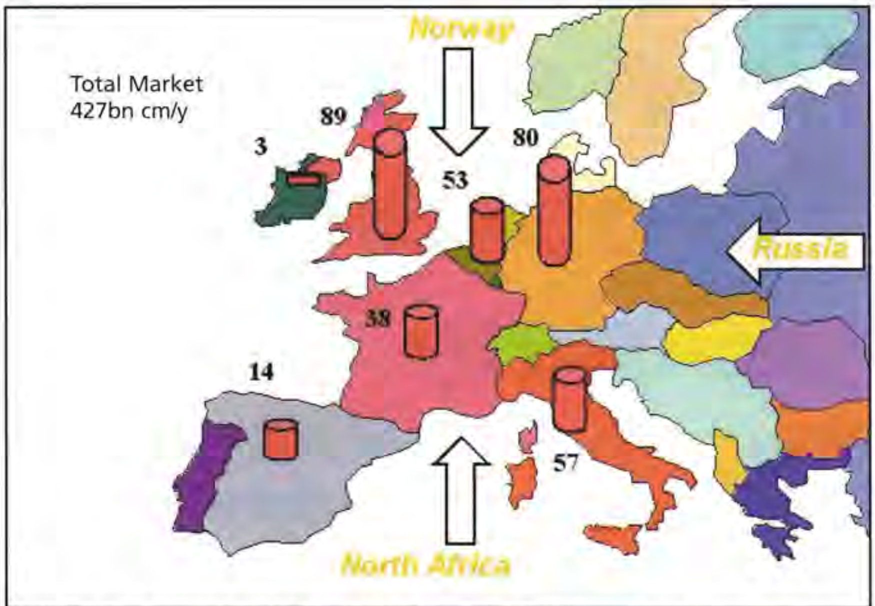

Figure 2: The European gas market (bn cm/y) Source: BP Amoco Statistical Review of World Energy, *June 1991*

Western Europe's gas production only satisfies 70% of the region's demand and this percentage will fall further in the longer term. International pipelines supply gas to fill the gap. Pipelines from Russia, Norway and Algeria are already operational and others are planned. Eni, for example, has proposed a 370-mile pipeline under the Mediterranean linking Libya to Sicily and is involved in the construction of a 727-mile pipeline under the Black Sea linking Russia to Turkey.

Interconnector role

The Interconnector pipeline enables shippers to capitalise on the demand for gas by providing the conduit through which gas can be supplied or traded within the rapidly growing markets of Europe. It can also provide the UK with an alternative source of gas supplies when indigenous gas suppliers cannot fulfil domestic demand. It is far more than just a physical pipeline between the UK and the Continent. It provides both the instrument and the opportunity to develop a free market for gas in Europe. Already, the total amount of gas traded far exceeds that physically transported – the Interconnector has effectively created a market.

Roger Cornish, Managing Director of Interconnector UK (IUK), which operates the pipeline, is aware of the important role his organisation has to play. 'Openness, transparency and availability need to be critical components of the growing Interconnector service. Our objective must be to move towards a level playing field to enable IUK services to be offered to as many companies as possible who wish to trade or ship gas. The service we offer at present is already one of the most complex and sophisticated of any gas pipeline system anywhere and in enhancing that service we must also increase its availability. This means making our gas management system – ISIS – more easily accessible to the market and we are beginning to investigate ways of doing that, perhaps via the Internet.'

He also sees Interconnector having a role to encourage capacity trades. 'Interconnector could facilitate capacity trading. Trading happens now in increasingly shorter time frames. The original contracts ran for 20 years, but now some shippers are selling capacity to meet market demand at a range of volumes and time intervals which will probably continue to shorten as the market develops.'

Cornish accepts that, to some extent, Interconnector has become a victim of its own success. 'When we first opened for business, the market was slow to seize the opportunity presented. Now, the market has been stimulated to such a degree that Interconnector is running to keep up and that has not always been easy given that we must secure consensus amongst our shippers in order to modify our operation.'

Traditionally, in the upstream gas industry, the product of a particular gas field is sold first, then the field is developed, knowing that the investment is covered by gas sales. In Cornish's view, if the gas market becomes a true com-

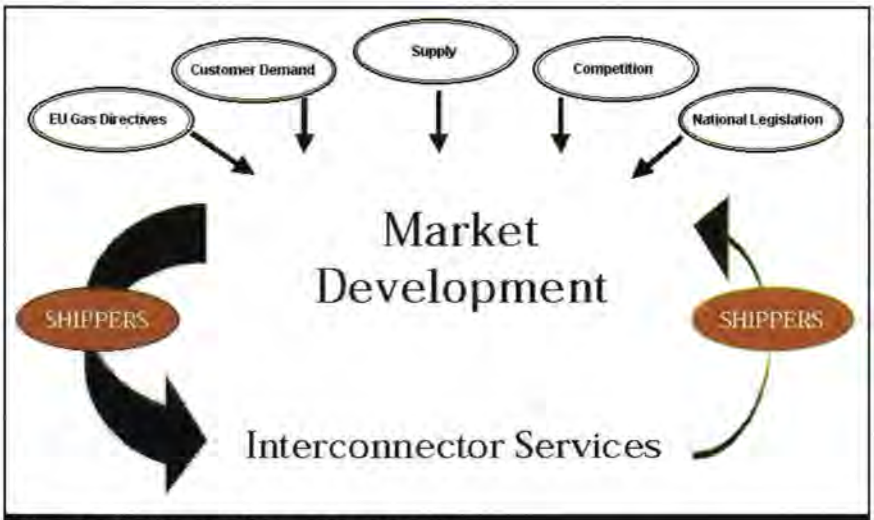

Figure 3: Development of Interconnector services

modity market, then resources and infrastructure could be developed before the market is secured. Already, BP has announced the construction of LNG tankers which are not committed to a particular delivery chain, just as the owners of Interconnector took a bold risk in building a pipeline system before the market had started to evolve.

Evolving market

The market is constantly evolving. Situations that were not previously envisaged are now challenging shippers and traders to be more creative and the business rules sometimes have to be modified to accommodate them. Changes to the business rules usually involve changes to the ISIS software.

In addition, as the market evolves, so the players must adapt to new conditions and circumstances. Many learn as they go along – at different speeds and with different requirements. As new players enter the market they must quickly catch up.

Interconnector is in constant dialogue with its shippers to improve and enhance the service on offer (see **Figure 3**). As such, they have a considerable say in what they want from the system and the ISIS software. Consequently, ISIS is in a continual development phase. Initially, at the start of the project, all the shippers stated their requirements. These were prioritised so that the pipeline could start up on schedule, with enhancements to the service added subsequently. The connection of the line, which brings in gas from the Elgin/Franklin and Shearwater fields, involved another expansion of the software.

Future flexibility

Terry Stephens is the Business Systems Manager for IUK. He defines the shape of ISIS and how it will evolve, working closely with the EDS team in Aberdeen who develop the software for IUK. 'In the future, the shippers will demand even greater flexibility from ISIS. There will be a requirement to trade unused capacity for short-term transfer with the possibility of hourly exchanges. Shippers will also need more tools to manage their inventory in the pipe for storage as well as for transportation.'

Inevitably, shippers are keen to implement new concepts quickly to take advantage of changing market conditions. Changes to the software are the consequence and the team works in close cooperation to ensure that new phases are completed as quickly as possible. Testing is a major element of the development process – about 40% of the software life-cycle process – and ISIS has to function perfectly every time.

The vision of the system being available over the Internet is also getting nearer. A pilot is scheduled for 2Q2001 in the UK, providing ISIS to shippers on connecting pipelines with slightly reduced functionality. One of the goals of the pilot is to better understand the technology and security issues, which are a major aspect of trading over the Web.

Impact of the Internet

The UK is at the forefront of gas competition in Europe. However, liberalisation and deregulation throughout Europe's gas industry are beginning to impact the traditional ways of the industry. The Internet and the digital economy are having a major impact on energy trading with markets and trading hubs emerging, both formal – as at the Belgian Hub – and informal, such as those at the flanges of Interconnector. In addition, trading in paper/forward transactions in both product and pipeline capacity is expected to increase.

The ability to trade electricity, gas and oil online and in real time in digital marketplaces will open up huge opportunities for energy companies. In the future, there is likely to be a much greater need for price transparency and far fewer barriers to participation by small traders throughout the world.

Web-based trading is taking its place alongside traditional exchanges and brokerages, but digital marketplaces redefine the volume of trade and diminish the scale of traditional operations. Trading in the energy market has become a high-powered information business and the challenge for energy trading and marketing companies is to align their transactions processes, risk management schemes, trading controls and administrative processes within an effective Web-based strategy.

To satisfy the needs of this growing international market, information systems are evolving. Compared with privately managed networks and highly prescriptive EDI (electronic data interchange) message formats, the Internet is flexible, inexpensive and available anytime and anywhere. Cornish is certain of its appeal. 'We can either grab at the opportunity it offers or be washed aside like some modern day King Canute attempting to ignore such an irresistible force. IUK, however, intends to seize these opportunities and use them to stimulate a service from which all those along the gas chain can benefit, thus providing Europe with an efficient, secure energy market to meet the global industrial challenge.'

**EDS is Interconnector UK Ltd's information technology partner and is responsible for the software and hardware that provides the information flows crucial to shippers using the*

Interconnector facts

- The Interconnector pipeline is linked to the gas grids of the UK and Belgium with a compression facility located at Bacton and a reception terminal at Zeebrugge.
- The 140-mile pipeline is capable of transporting 20bn cm/y from Bacton to Zeebrugge (forward flow) or 8.5bn cm/y from Zeebrugge to Bacton (reverse flow).
- The pipeline became operational in October 1998 and is operated by Interconnector UK Ltd (IUK).
- There are ten shareholders of Interconnector (UK) Ltd and sixteen shippers or customers who have purchased long-term capacity commitments.

South Korean energy import bill soars

Photo: David Hayes

The cost of South Korea's energy import bill is expected to show a large increase when figures are totalled for 2000 – a year in which energy consumption surged, reflecting the nation's economic growth during the first three quarters. *David Hayes* reports.

Warnings that energy import costs were poised to soar appeared early in the year. Energy import costs grew 20.3% during 1Q2000 to total $9.1bn, compared with 1Q1999, due to the doubling of crude oil prices. In fact, the actual increase in the energy import bill was only about 5% as winter 2000 was relatively mild by Korean standards.

Whether South Korea's energy consumption growth will continue into 2001 is now being questioned as analysts are warning of a fourth quarter economic slow down due to increased bankruptcies among debt laden companies and resulting job losses. Inflation caused by rising international oil prices has also hit consumer spending in the third quarter, while an expected cooling in global demand for electronics (South Korea's biggest export category) is likely to slow down investment and lower energy consumption. The recent US economic slowdown tends to confirm these fears.

The Ministry of Commerce, Industry and Energy (MOCIE) originally forecast the country's energy imports at $30.3bn for 2000, but the actual figure will be somewhat higher due to the oil price increase. Meanwhile, the government remains concerned at South Korea's high level of energy consumption and continues to promote development of alternative energy sources. While per capita annual energy consumption is 3.93 toe, slightly lower than Japan's 4.08 toe , South Korea's GDP per capita is one-third that of Japan's and consequently the country's energy efficiency performance is just one-third of Japan's.

According to government statistics the average mileage driven by passenger cars in South Korea is 19,500 km, almost double the 10,000 km recorded in Japan and similar to the US at 19,100 km. Similarly, average gasoline consumption per car is 3.1 toe in South Korea, compared with 2.7 toe in the US, 1.3 toe in Japan, 1.7 toe in France and 1.2 toe in Italy.

South Korea's energy consumption pattern is a product of consumer trends and an energy intensive industrial base. Industrial enterprises in South Korea account for 72.5% of the nation's energy consumption, compared with 62.7% in the US and 60.8% in Japan, while the OECD average is 60.6%.

Energy pricing is partly responsible for this situation. Compared with the OECD average index of 100, South Korea's electricity price for consumer use is 75%, while electricity for industrial use is 72%. Until recently light oil was 59% and LPG 61%. Only gasoline, priced at 110%, was higher than the OECD average.

In 1999 South Korea imported 1,058mn barrels of crude oil and oil products, a 6% increase compared with 1998 and almost exactly the same volume of crude oil and oil products imported in 1997 when South Korea's financial crisis first struck. The total 1999 import figure consists of 874mn barrels of crude and 184.5mn barrels of oil products, the same volumes as in 1997, with both 1999 totals showing a 6% increase over figures for 1998. In 1Q2000 crude oil and oil product imports totalled 293.5mn barrels, a 5.4% increase compared 1Q1999.

Imports and consumption of other energy products have grown as well. In 1999 South Korea consumed 77mn barrels of LPG, a 13.2% increase compared with 1998. In 1Q2000 LPG use reached 23.3mn barrels, a 17.7% increase compared with 19.8mn barrels in the same period in 1999.

South Korea's LNG import total also grew in 1999, reaching 12.97mn tonnes, a 21.7% increase compared with 10.6mn tonnes in 1998. In 1Q2000 LNG imports grew 22% to 4.8mn tonnes compared with 3.9mn tonnes in the same period in 1999. The main reason for the first quarter growth in LNG demand was increased use of city gas for residential and office heating during the winter months. In 1999 rising city gas consumption accounted for about 70% of increased LNG use during the year, while increased power generation accounted for the rest.

Coal use also grew in 1999, due mostly to increased coal-fired generation as new coal-fired stations came onstream. In contrast, coal use by the steel and cement industries remained stable. Some 28.3mn tonnes of coal were used for power generation in 1999, up almost 10% compared with 25.6mn tonnes in 1998. Coal use for power generation is expected to show some growth when figures are published for 2000 as coal prices continue to fall in South Korea, while more coal-fired stations are being started up.

Electricity generation and consumption also continues to grow. In 1999 Kepco generated 239,325 GWh, an 11.1% increase compared with 215,300 GWh in 1998. Total electricity consumption reached 214,215 GWh in 1999, a 10.9% increase compared with 193,470 GWh in 1998.

Increased power generation and consumption continued into 2000, with power generation and electricity consumption both rising 16% each during the first quarter compared with the same period in 1999. South Korea's strong economic performance in 1H2000 has been responsible for the increase in electricity consumption. According to official figures, industrial consumption of electricity accounted for half of the first quarter increase while commercial use of electricity represented 38% of the increase.

Energy consumption grew in 1999 after total energy demand had dropped sharply in 1998 as South Korea weathered the worst of its economic recession. As a result, by the beginning of 2000 the government felt confident enough to finalise a number of long-delayed long-term energy forecasts.

Energy supply plan

In January 2000, after an 18-month delay, the government published its fifth long-term electricity supply plan. The government has forecast that electricity consumption will grow by an average of 5.2% during the first decade of the new millenium. To ensure sufficient power supplies are available to meet long-term electricity demand growth, the government plans that South Korea's installed generating capacity will increase by 58.8% from 46,980 MW at the end of 1999 to 74,600 MW by the end of 2010.

Publication of the long-term electricity forecast was followed two months later by publication of the fifth long-term natural gas supply forecast in March 2000; also 18 months behind schedule. The natural gas plan was delayed by the electricity plan as Korea Gas Corporation (Kogas) could not finalise gas consumption forecasts until Korea Electric Power Corporation (Kepco) first published its gas-fired generation plans.

According to the new long-term plan, demand for natural gas will grow at an average annual rate of 4.7% between 1999 and 2010. Imports of natural gas will grow by 61.5% from 12.97mn tonnes in 1999 to 20.97mn tonnes in 2010. The main reason for the planned growth in natural gas consumption will be the electricity industry's use of LNG for power generation. However, increased gas consumption also will result from the increased availability of gas countrywide as the government plans to complete construction of a national high pressure gas transmission grid by the end of 2002.

Meanwhile, speculation has grown that Kogas has been invited to participate in two more LNG trains in Qatar's Ras Laffan LNG Company (Rasgas) project, although Kogas and the South Korean Energy Ministery have not made any comment. Kogas is one of five Rasgas partners and started taking Rasgas LNG in 1999 under a 25-year, 4.8mn t/y agreement.

LNG competition

Growing LNG imports once again have swung attention to the issue of introducing competition to the domestic LNG market, now monopolised by Kogas. Some South Korean companies already are preparing for the eventual opening of the LNG market. Pohang Iron & Steel Corporation (POSCO), for example, is building an LNG receiving terminal at its Kwangyang steel mill in the south of the Korean peninsular.

Apart from supplying gas-fired power stations being built at Kwangyang steel mill and POSCO's Pohang steel mill on the east coast, the Kwangyang terminal also is expected to supply other customers with LNG surplus to POSCO's own requirements. Kepco also plans to import LNG, even though it was the South Korean power company itself that orginally established Kogas to import LNG and in which it maintains a 35.5% shareholding.

Meanwhile, Kogas is carrying on with its huge construction programme to increase LNG import and handling facilities while it is expanding its national gas transmission pipeline network. Construction of additional LNG storage facilities has not been seriously affected by South Korea's economic crisis, although completion of some new transmission pipeline sections has been delayed by up to 24 months as gas consumption growth is likely to remain slower than previously forecasted for several years.

In 1997 Kogas awarded MW Kellogg a basic engineering and consultancy contract for its third LNG import terminal to be built in the south of the Korean Peninsular, near the eastern end of a transmission pipeline loop that Kogas is building to connect the cities of Kwangju and Pusan. To be constructed at Tongyong in South Kyongsang Province, the third LNG terminal will help increase security of gas supply to the national transmission network as well as boost gas utilisation in the southern region. In fact, a number of city gas companies distributing an LPG/air gas mix already are well established in several southern cities, but are waiting for natural gas supplies to arrive to convert their systems and expand business.

Plans are understood to be proceeding on schedule, with the first phase of the new terminal due for completion in August 2002. Plans call for three 140,000 kilolitre storage tanks to be constructed initially, capable of handling about 4mn t/y of LNG.

Depending on gas demand growth in the south and the effect of other organisations such as POSCO building its own LNG import facilities, Kogas plans to almost double the Tongyong terminal's LNG storage capacity by installing two 200,000 kilolitre storage tanks in Phase 2. A third expansion phase to install one more 200,000 kilolitre storage tank also is being proposed.

Gas use for power generation will create the initial baseload demand to ensure the economic viability of Tongyong LNG terminal. Kepco plans to convert an existing coal-fired power station in Pusan to burn gas and will build a new combined cycle station to increase electricity supplies to the industrial port city. Elsewhere in the southeast region Kepco has started to build new gas-fired power stations in Taegu and Ulsan intended for peak load shaving.

By the end of 2002 Kogas' plans call for the utility to operate three LNG terminals with a total of 29 storage tanks capable of holding 3.5mn tonnes of LNG. The three terminals will be able to send out 6,250 tonnes of LNG per hour for transmission countrywide through Kogas' under-construction national high pressure pipeline grid.

Construction of the national gas transmission pipeline network is underway at a number of sites, although completion of some sections has been delayed due to South Korea's economic recession. The 260-km southern pipeline loop route from Kwangju to Changwon near Pusan was due to be completed in December 2000, two years later than originally planned. Plans call for a transmission pipeline to be built from the third terminal at Tongyong to feed into the southern pipeline loop. The 50-km pipeline is due for completion to coincide with the planned commissioning of Tongyong receiving terminal in August 2002.

Also delayed is a 211-km coastal pipeline between Pyongtaek terminal and Iksan on the west coast. The pipeline is being built as a second loop to supply the central region from Pyongtaek terminal.

Electric restructuring

Meanwhile, plans to reorganise South Korea's electricity industry are being held up by objections from the official labour union of state-owned Korea Electric Power Corporation (KEPCO) which fears that widespread job losses will result from the restructuring and by widespread public opposition to local conglomerates and foreign investors being given large stake holdings in KEPCO.

Under the restructuring plans KEPCO is due to reorganise its 42 thermal and hydroelectric power stations into five power companies which will be sold off through share issuing and auctions. The assets of each company are estimated to be valued at between $2.5bn and $4bn. However, KEPCO's nuclear power plants, along with its transmission and distribution network, will remain under state control – although power distribution activities will later be sold off and distribution eventually opened to competition.

Under the government's reorganisation plan, South Korea's 30 largest 'chaebol' or conglomerates, including well-known names such as Samsung and Hyundai, will be barred from acquiring any of the five planned KEPCO affiliate power companies unless they complete ongoing corporate restructuring reforms imposed as part of efforts to solve South Korea's financial crisis. Foreign investors, meanwhile, will be able to buy up to 30% of KEPCO, including management control of two of the five new KEPCO affiliate generating companies.

Opposition in the national assembly late in 1999 blocked the passage of a privatisation bill for KEPCO.

At present the government owns 52.2% of KEPCO, while the remaining 47.8% of shares are publicly listed. To avoid placing too much equity in the market at one time the government plans to stagger the sale of the five new power companies. The five currently account for 27,573 MW, or 62.2% of KEPCO's 44,427 MW total installed generating capacity.

For the moment KEPCO's management and the government have a tough task winning public and labour union support for their plans. If restructuring proceeds by the end of this year each of the five generating companies initially will be allocated between 4,910 MW to 6,346 MW installed generating capacity. KEPCO's nuclear facilities will total 13,716 MW. The generating companies will sell their electricity production to KEPCO. Later a British-type electricity pool system will be established and all generators will sell into the pool.

Internal reorganisation

Although KEPCO's privatisation and restructuring plans have not received official approval, the utility already has started to reorganise internally ready for when the privatisation process begins. In March 2000 KEPCO reorganised its power generation department into six divisions that sell power to its transmission department.

Five of the six divisions have been allocated the power plants they will operate when they are sold off as private generating companies. The sixth division operates KEPCO's nuclear stations. KEPCO's power exchange department is in charge of power purchasing for which a system of marginal pricing is used.

Meanwhile, power demand grew ahead of government forecasts in 2000 leaving KEPCO with a 9% reserve generating ratio due to the early hot, dry summer and the lack of rainfall. Peak load demand reached 40,784 MW at the start of July, a 9.36% increase compared with 37,293 MW in 1999 and well ahead of the previous forecast of 39,509 MW for the year.

Colour-coded needle and valve handles

Hoke believes its new colour-coded needle and ball valve handles will quickly and easily add valve identification and maximum safety to new and existing installations.

This solution to what can be a troublesome problem enables identification changes to be made without removing valves from the system. Eight bright colours are available for the valves, increasing not only safety, but aesthetics.

The writing of the system operation procedures is also simplified, as reference to colours can be made in addition to valve identifications. Systems may be individually colour-coded, such as using green handles for air and red handles for hydrogen, thereby helping to prevent accidental opening or closing.

Tel: +44 (0)20 8423 0113
Fax: +44 (0)20 8423 5933

Switch safety

Able Instruments & Controls has recently introduced a number of new temperature, pressure and differential switches to its product portfolio.

Safety considerations are often the determining factor when specifying an industrial pressure or temperature switch and the redesigned 120 Series is said to be suitable for situations where potentially explosive or highly corrosive atmospheres exist.

The series meets IP66 standards, hence applications include chemical plants, refineries, drill rigs, pipelines and coal and grain dust areas. Measurement capability allows temperature switching between –115°C to 340°C and pressure switching between full vacuum and 344 bar. The 120 Series also includes some ultra-low pressure sensors designated for testing applications such as furnace drafts, tank blanketing and low gas purge lines.

Units may also have one or two switches with high switch ratings of up to 30 amp 300 VAC, allowing heavy machinery such as pumps to be wired directly to the switch without the requirement for additional auxiliary relays.

All sensors are available in a variety of materials including stainless steel, brass, viton, buna-N, monel, tantalum, hastelloy B and C, whilst accessories such as thermowells are available from stock.

Tel: +44 (0)118 931 1188
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Cure your bladder problem!

For companies involved in the distribution of pressurised liquids, Pronal has developed a flexible bladder accumulator to neutralise the effect of excess pressure in pipes, at the valves in particular. The product is designed to eliminate 'water hammer,' caused by pressure differentials when liquid flows through pipes of decreasing dimension, and so prevents damage to the distribution circuits.

The sealed bladder accumulators are fitted in pressurised vessels and tanks to allow volume variations. The bladder provides an insulating and protective (shock-absorbing) interface between the tank (or expansion vessel) and the water or hydrocarbons distribution circuit.

Each bladder is designed and manufactured to measure according to the exact requirements of the container in which it is fitted. Made from polyurethanes or special rubber, the bladder possesses mechanical properties: strength, flexibility, homogeneity, high expansion capacity and tolerance towards toxic products.

Properties of the bladder include: food grade for use in water distribution networks; resistance to liquid chemicals; oil and hydrocarbons; anti-extrusion properties. It is able to withstand temperatures of 60°C to 80°C and pressures above 20 bars.

Tel: +33 3 20 99 75 00
Fax: +33 3 20 99 75 20

Accurate current interruption

Upgrading of the BAC Corrosion Control GCU series of DC current interrupters, according to the manufacturer, allows more accurate, easy, versatile and the economic synchronous switching of cathodic protection stations.

The interrupters are designed to save time during maintenance and survey periods by accurately switching 'on' and 'off' cathodic protection DC current sources in order that the true polarised pipe to soil potential, used as a criterion for cathodic protective levels, may be recorded on the pipeline. The instant 'off' is considered accurate, as it eliminates an additional voltage drop when the system is switched on and the subsequent volt drop caused by cathodic protection current flow in the soil.

The current interrupters are supplied in three ratings to cater for most types and capacity of DC power sources.

The solid state unit is housed in a rugged IP65 sealed enclosure built to withstand a wide range of field conditions. Control is through an LCD menu screen which also indicates the condition of the built-in NiMH battery.

Tel: +44 (0)1952 290321
Fax: +44 (0)1952 290325

Efficiency software

Software has been developed by CMG Admiral – part of information and communication technology services group CMG – to help oil companies and fuel distributors minimise costs and maximise efficiency across the supply chain.

CMG:Cross is a scheduling system which acts as an advanced decision support system. According to the manufacturer, it improves workload balancing overtime and optimises use of an oil company's own and third-party vehicle fleets. The software regulates stock levels held at petrol stations and maintains high service levels. The system can also be adapted to satisfy local regulatory requirements and can accommodate most languages, due to its global usability.

The system, according to CMG, has provided up to a 15% reduction in distribution costs and up to a 40% reduction in stock levels.

Tel: +44 (0)20 7592 4755
Fax: +44 (0)20 7592 4157

Environmentally based esters

Uniqema has developed a new range of naturally based synthetic esters under the Priolube™ brand for use as basefluids in hydraulic equipment.

Worldwide there is an increasing awareness of the environmental impact of many lubricant formulations. Many regions have already restricted the use of mineral oil-based products and require the use of biodegradable fluids. The new Priolube products have been created with this in mind and cover two specific market segments for hydraulic systems.

Fluid temperatures in mobile hydraulic systems can increase up to 100°C, so Uniqema has created a range of oleate based esters: Priolube 2088 and 2089, which are both ISO 46 grade fluids. These products offer full biodegradeability to all major standards, formulation from natural and renewable raw materials, long fluid lifetime due to good oxidative stability and can be used in all climates due to their low temperature and viscosity properties.

In hydraulic systems where temperatures exceed 100°C, hydraulic fluids need a high degree of oxidative stability as well as environmentally acceptable properties. Hence the creation of highly oxidative and thermally stable synthetic esters Priolube 1848 and 1849, as a new class of biodegradable ISO 46 grade fluids. They offer long life fluid time due to their oxidative stability in severe conditions, biodegradability, improved pump life due to good lubrication and demulsification properties, applicability in all climates due to good low temperature and viscosity properties and reduced downtime because of long-term filterability.

Three other products have also been created with similar performance characteristics: Priolube 1850 is an ISO32 grade complex ester while Priolube 1847 and 1851 can be used as thickeners to upgrade lower viscosity basefluids to higher ISO grade products.

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61 New Cavendish Street, London W1G 7AR, UK

NEW Publications

Motor Fuel Markets Prices and Taxes – Annual Review 2001*

Derek Louden (HyperActiv Group, Active House, Settstones House, Uppermill, Lancs OL3 6LN, UK). ISBN 0 95400 450 7. 339 pages. Price £53.

This guide to motor fuel prices and environmental taxes across the European Union will be of interest to economists from any background, but particularly energy economists. The guide should also aid politicians looking for solutions to present day issues. Academically too, the guide is of use for students involved in environmental economics or taxation. Regional policy is discussed in detail, particularly how decisions made for the benefit of urban locations had an adverse impact on rural areas. In-depth analysis of the Office of Fair Trading (OFT) and the way in which its affairs are carried out are discussed, as are the relative merits of policy options being used to deter road travel, and the impact of these decisions on the professed aim of social inclusion. The author hopes to update this work on a regular basis and would welcome suggestions and contributions from all members of the oil and gas industry.

Industrial Cleaning Technology*

Joe Harrington (Kluwer Academic Publishers, PO Box 17, 3300 Dordrecht, The Netherlands). ISBN 0 79236 748 0. 290 pages.

This book contains a comprehensive review of current industrial cleaning techniques including those using low, medium and high pressure water, solvents, chemical compounds and foam, wet and soluble abrasives and the latest computerised in-line automatic techniques. Emphasis is placed on the practical aspects of designing, manufacturing and operating cleaning equipment and systems. Industrial cleaning applications include municipal drains and sewers, road tanker and container depots, chemical plants, offshore oil and gas platforms and other manufacturing processes. The book contains a selection of case studies relating to typical industrial cleaning problems and injuries associated with high pressure water jetting activities. It also examines the increasing effect of international health, safety, training and environmental legislation on cleaning activities, with particular reference to European Directives, the US and regulations controlling cleaning standards, procedures and plant design in the pharmaceutical and food processing industries. Useful information sources are listed throughout the book.

Fuels International: Advances in Fuels and Automotive Energy*

(Leaf Coppin Publishing, PO Box 111, Deal, Kent CT14 6SX, UK). ISSN 1470 4625. Price (Volume 1): £291.

This new scientific quarterly journal is aimed at those working in industrial, academic, environmental, and military research contexts, who need to keep abreast of developments in fuels, energy and propulsion. Fuel is becoming a major subject of research interest as are emissions control requirements in relation to petroleum-derived fuels and lean-burn demands. The search for alternative and novel energy sources in the face of a finite supply of petroleum, are driving fuel science and technology in new directions. Advanced propulsion technologies, such as fuel cells, hybrid engines, and bioderived fuels, together with increasing innovation in the physics and chemistry of propulsive fuels and combustion, in fuel additives, and in fuel delivery systems, are all of increasing importance. The publisher invites experts in the fields mentioned above to send it papers for potential publication in the journal.

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YOUR OFFICE AWAY FROM HOME

Internet sources and issues relevant to the energy industries – 2001 update

IFEG is holding an afternoon seminar on 22 May 2001 to update members on finding energy information on the web, and the legal implications of using such information. There will also be a presentation from our sponsor, TDNet, about its One Stop E-Journal Management Tool. The seminar will be free to IFEG members.

Please contact Sally Ball to register for more information about the seminar or about joining IFEG.

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Some New Editions to Library Stock

- *Analyser Systems: A Guide to Maintenance Management.* Engineering Equipment and Materials Users Association, (EEMUA), UK, 2000.
- *Energy Policies of IEA Countries: 2000 Review.* International Energy Agency (IEA) Organisation for Economic Cooperation and Development OECD, Paris, France, 2000.
- *Manual of Petroleum Measurement Standards: Chapter 3 – Tank Gauging: Section 6 – Measurement of Liquid Hydrocarbons by Hybrid Tank Management Systems: Measurement Coordination.* American Petroleum Institute (AIP), Washington DC, US, 2001.
- *Minerals and Petroleum: Exploration and Development in Northern Ireland 1997–2000.* Department of Enterprise, Trade and Investment (DTI), Belfast, Northern Ireland, 2000.

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Details: Orient Exhibitions, UK
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Fax: +44 (0)1732 763606
www.tradepartners.gov.uk

19–20 **Florence**
Italian Power Executive Workshop
Details: CERA, France
Tel: +33 1 42 44 10 18
Fax: +33 1 40 15 05 22
e: dcallanan@cera.com
www.cera.com

22–25 **Abu Dhabi**
Seismic for Enhanced Reservior Characterisation
Details: Penwell, US
Tel: +1 918 831 9160
Fax: +1 918 831 9161
e: gulfseismic@penwell.com
www.penwell.com

22–27 **West Sussex**
The Five Day MBA: Developing the High Performance Manager
Details: Hawksmere, UK
Tel: +44 (0)20 7881 1817
Fax: +44 (0)20 7730 5285
e: leon@hawksmere.co.uk
www.hawksmere.co.uk

23–24 **Vienna**
Structured Commodity and Trade Finance in the CIS
Details: IBC Global Conferences, UK
Tel: +44 (0)1932 893857
Fax: +44 (0)01932 893893
e: cust.serv@informa.com
www.informa.com

23–24 **London**
Reserve Acquisitions, Disposals and Swaps
Details: SMi, UK
Tel: +44 (0)20 7252 2222
Fax: +44 (0)20 7252 2272
e: customer_services@smiconferences.co.uk
www.smi-conferences.co.uk

23–27 **Aberdeen**
Subsea Awareness Course
Details: Society for Underwater Technology, UK
Tel: +44 (0)1224 823637
Fax: +44 (0)1224 820236
e: admin@sutadmin.demon.co.uk

24–25 **Vienna**
European Fuels Conference
Details: WRA, UK
Tel: +44 (0)1242 529090
Fax: +44 (0)1242 529060
www.wraconferences.com

24–26 **Birmingham**
Understanding Heat Treatment
Details: Wolfson Heat Treatment Centre, UK
Tel: +44 (0)121 359 3611
fax: +44 (0)121 359 8910
e: WHTC@aston.ac.uk

24–26 **US**
SIMDIS Operator Course
Details: Analytical Controls, Netherlands
Tel: +31 10 4624811
Fax: +31 10 4626330
acbv@analytical-controls.com

25–26 **London**
Deepwater E&P
Details: SMi Conferences, UK
Tel: +44 (0)20 7252 2222
Fax: +44 (0)20 7252 2272
e: customer_services@smiconferences.co.uk

26 **London**
PED –The Final Countdown
Details: TWI, UK
Tel: +44 (0)1223 891162
Fax: +44 (0)1223 894363
e: meetings@twi.co.uk

26 **Aberdeen**
Process Industry Measurement Uncertainty Workshop
Details: NEL, UK
Tel: +44 (0)1355 220222
Fax:+44 (0)1355 272626
e: mhughes@nel.uk

30–1 May **London**
Asset Management for Utilities
Details: IQPC, UK
Tel: +44 (0)20 7368 9300
Fax: +44 (0)20 7368 9301
e: assetmgmt@iqpc.co.uk

MAY 2001

2–3 **Rio de Janeiro**
Latin Gas 2001
Details: Global Pacific, US
Tel: +1 281 597 9578
Fax: +1 281 597 9589
e: glopacam@wt.net

2–3 **Bournemouth**
Federation of Petroleum Suppliers' Exhibition and Conference
Details: Federation of Petroleum Suppliers
Tel: +44 (0)1565 631313
Fax: +44 (0)1565 631314
e: Fps@btinternet.com

3 **London**
Convenience Retailing 2001
Details: IGD, UK
Tel: +44 (0)1923 857141
Fax: +44 (0)1923 852531
e: conferences@igd.com

3–6 **Malta**
ERPEC Europe 2001
Details: McLean Events, UK
Tel: +44 (0)1483 810670
Fax: +44 (0)1932 222324
e: events@com-a-tec.de

7–9 **Dubai**
Land Tank and Shipboard Measurement
Contact: Abacus International, UK
Tel: +44 (0)1953 497099
Fax: +44 (0)1953 497098
e: information@abacus-int.com

7–9 **Arizona**
ASTM Committee D15 on Engine Coolants
Details: ASTM, US
Tel: +1 601 832 9500
Fax: +1 610 832 9555
e: gcollins@astm.org

7–11 **Rotterdam**
Reformulyzer AC Operator Course
Details: Analytical Controls, Netherlands
Tel: +31 10 4624811
Fax: +31 10 4626330
acbv@analytical-controls.com

14–15 **London**
Oil and Gas E-Business Summit
Details: IBC Global Conferences, UK
Tel: +44 (0)1932 893857
Fax: +44 (0)1932 893894
e:cust.serv@informa.com
www.informa.com

14–15 **Abu Dhabi**
Oil and Gas Pipelines in the Middle East
Details: The Energy Exchange, UK
Tel: +44 (0)1242 529090
Fax: +44 (0)1242 529060
e: s.church@theenergyexchange.co.uk

15–16 **London**
Analysing International Border Disputes
Details: Global Business Network, UK
Tel: +44 (0)20 7291 1030
Fax: +44 (0)20 7291 1001
e: info@gbnuk.com

Membership News

NEW CORPORATES

Mr A Akinjide, Squire Sanders & Dempsey
Mr N J Andrews, Staffordshire
Mr P J Arscott, Kuwait Petroleum (GB) Ltd
Mr J Balasingam, Singapore
Mr U Bilaloglu, SCI Ltd
Mr M R Bowers, Hampshire
Dr E J Butler, London
Mr G Byrne, Oil Industry Links Ltd
Mr D Cardarelli, Odebrecht Oil & Gas
Mr P J Cattrall, Kent
Ms H S Cowling, Herts
Ms A C Daborn, American Express Europe Ltd
Mr C Davidson, Scania GB Ltd
Mr G P Davies, South Yorkshire
Dr B W Davies, Infineum UK Ltd
Ms J Edwards, Standard Chartered Bank
Mr A D Fisher, London
Mr R Garcka, Standard Chartered Bank
Mr A Greenwood, Peter Seagroatt & Associates
Mr T Gruchalla-Wesierski, Macleod Dixon
Mr P C Hibbert, SOFEC Inc
Dr D Hoskin, Exxon Mobil Research & Engineering
Mr N J Howe, Howe & Company
Mr R B Kalloo, Northland Energy Corporation (UK) Ltd
Mr R G Kommareddi, Caltex Corporation
Dr G Lawrence, The Really Easy Imaging Company Ltd
Mr A N Mackay, Conoco Continental Holding GmbH
Dr A T Mann, ERT (Orkney) Ltd
Dr M Marafi, Kuwait
Mr P T McHugh, Glasgow
Mr M Melnyk, Arthur Andersen
Mr E J Mohideen, India
Mr S Nair, India
Mr S Robertshaw, Middlesex
Ms K Sansom, Harrison Lovegrove and Company
Mr N Satras, Motor Oil (Hellas) Corinth Refinery
Mr T Sharman, Saudi Petroleum Overseas Ltd
Mr M Smirnov, Energy Resources UK Ltd
Mr N Subin, India
Mr W F Tong, Government Laboratory (HKSAR)
Mr S Tyrrell, Portsmouth
Mr P Veth, Thermo Euroglas
Mr J S Vig, Inland Revenue
Mr A G Waine, Chester
Ms A J Westwood, Leicestershire
Dr T Wong, China
Mr J G Wood, Deep Water Slender Wells Ltd
Mr J Yiallouros, Greece
Dr Y C Yip, Hong Kong
Mr S M Young, BP Amoco
Mr K F Zakirov, Russia
Mr S Zehnder, Italy

STUDENTS

Mr M M Ahmed, Imperial College
Mr Z A Ahmed, Imperial College
Mr A O Akemu, London
Mr F R Dalgleish, Cranfield University
Mr J Doodson, Cranfield University
Mr B Garwal, London
Mr T Gasse, Cranfield University
Mr M Ishtewi, London
Mr D L Marokane, London
Mr M Moreno, University Of Surrey
Mr G Nunez, Imperial College
Ms J A Omene, Imperial College
Mr O Yergaliyev, London

STUDENT PRIZEWINNER

Dr Y-S Kim, Seoul National University

DEATHS

We regret to announce the deaths of the following members over the past few months:

	Born
Sir Archibald Forster	1928
Mr G S Forsyth	1926
Mr M L Ryall	1931
Alexander Fraser Rose	1907

NEW FELLOW

Ir K S Szeto FInstPet

Ir K S Szeto graduated in Mechanical Engineering and later Marine Engineering from Hong Kong Polytechnic University. He worked in a consultancy firm before joining Shell Hong Kong Ltd in 1981. He is a Chartered Engineer and Fellow of the Institute of Marine Engineers and the Royal Institution of Naval Architects. He was Installation Maintenance Manager of the Shell Tsing Yi Installation which has a 19.6 hectare area and fully automatic installation, Senior Project Engineer on designing/managing the oil terminal, wharf and jetties projects in 1996. He is also a Registered Professional Engineer in Hong Kong and Fellow of The Hong Kong Institution of Engineers (HKIE). He was elected a Member of the first Legislative Council Election Committee for Transport Subsector Election for the session 1998/2000. Now he is the Technical Services Manager, North East Asia Region in Shell Marine Products and has been re-elected as Committee Member of the second Legislative Council Election Committee for The Transport Subsector Election for the session 2000/2002.

PEOPLE

Mark Thatcher has been appointed President and Chief Executive of ABB Vecto Gray, supplier of drilling and production equipment.

PYPSA International has named **Robert MacMillan Jr** Senior Vice President and Chief Financial Officer, responsible for finance and administration.

BJ Services has appointed **Kevin deVerteuil** Country Manager for Nigeria with the Well Services–Europe/Africa Division.

Nelson Narciso has filled the new position of ABB Oil, Gas and Petrochemicals' Angola Regional Manager, based in Luanda.

Apache Corporation has made two recent appointments. **Zurab Kobiashvili** has been named Senior Vice President and general Counsel and **Eric Harry** has been promoted to Vice President and Associate General Counsel.

Andy Toffolo has been named Maintenance Director of Caxios.

Baron Philippe Bodson, Dr Walter Seufert and Dr Gerd Zuncke have retired from the Supervisory Board of Wintershall. They have been succeeded by **Bernhard Walter**, **Dr Jürgen Hambrecht** and **Dr John Feldmann**.

OBITUARIES

Sir Archibald Forster FInstPet
1928–2001

We regret to announce the death at the age of 73, of Sir Archibald Forster, ex-Chairman and Chief Executive of Esso and former IP President from 1988–1990.

After graduating from the University of Birmingham and completing a period of National Service in the Royal Air Force, he joined the Technical Department of Esso's Fawley Refinery in 1951.

After holding a number of appointments with Esso at Fawley and in London, he became Manager of Milford Haven refinery in 1962, and became Manager of Fawley refinery in 1964. In 1973 he moved to the Exxon Corporation in New York as Executive Assistant to the Chairman and later in 1974, Manager of Exxon's Corporate Planning Coordination Department. He moved back to Esso Europe in 1975 and was appointed Vice President of Logistics. In 1980, he became Chairman and Chief Executive of Esso Petroleum, a position he held until his retirement in 1993.

Throughout his career he received many honours which included a Knighthood in the 1987 Birthday Honours List and Honorary Doctorates of Science from Birmingham, Loughborough and Southampton Universities. He also sat on many committees including Presidential appointments at the Institute of Petroleum and the Institute of Chemical Engineers, Director of the UK Centre for Economics and Environmental Development and non-Executive Director of United Newspapers.

He leaves a wife and three daughters.

Alexander (Sandy) Fraser Rose FInstPet
1907–2001

It is with deep regret that we report the passing of Sandy Rose, the first Chairman of the Aberdeen Branch and a stalwart of the Institute since 1955.

In 1922, Sandy began his career as an indentured engineering apprentice at the Inverurie Locomotive Works in Aberdeenshire. On completion of his indentures in 1928, he went to sea as a ship's engineer and during a year of voyaging to Australia, where many ports of call were in the Persian Gulf, he learned of oil drilling efforts in the region. After returning home, he joined the Anglo-Iranian Oil Company (which later became BP) as a drilling superintendent posted to Abadan where he was responsible for the pipelaying of oil and water services to the major refinery in Abu Dhabi. During World War Two he was involved in supply and distribution of fuel to the armed forces and was part of the team that developed specialist fuels for military vehicles through the use of cracking plants. In the post-War period he joined Texaco as Manager in its refineries in Immingham and Grangemouth. Prior to his retirement in 1962, he was the Depot Manager in Inverness.

In 1971 he helped form the Aberdeen Branch of the IP and was elected its first Chairman. In 1978, he was awarded an Honourary Fellowship by the Branch in recognition of his services.

Sandy was a 'weel-kent' and respected figure, still attending branch activities well into his eighties. He will be greatly missed.

IP Discussion Groups & Events

IP THE INSTITUTE OF PETROLEUM

Branch Activities

Humber

Contact:	*Dave Hughes Tel: +44 (0)1469 555237*
5 April:	Ladies Evening
10 May:	Visit to Alstom Gas Turbines, Lincoln

North East

Contact:	*John Sparke Tel: +44 (0)1642 546411*
24 April:	7 pm: VOCs at Oil Terminals, by Lee Scott, Costain Oil, Gas and Process Ltd
22 May:	Visit to BG Technology Spadeadam Test Site

Energy, Economics, Environment
Discussion Groups
Please notify the contacts if you plan to attend any of the advertised events. All events will take place at the IP unless stated otherwise
Institute of Petroleum, 61 New Cavendish Street, London W1G 7AR, UK
Tel: +44 (0)20 7467 7100
Fax: +44 (0)20 7255 1472
e: jsandrock@petroleum.co.uk

Gordon Forsyth FInst Pet
1926–2001

We are sorry to announce the death of Gordon Forsyth, a former IP Honourary Treasurer and Trustee of the IP Pension Fund.

After graduating in economics at the University of Glasgow and qualifying as a chartered accountant he joined BP in 1959 as an accountant in the Exploration and Production Division of Finance and Accounts Department, responsible for crude oil supply contracts and concession matters. In 1966, he was appointed Regional Finance Manager for the Middle East, Crude Oil Supply and UK Exploration and later Assistant Chief Accountant, Finance and Accounts Department. In 1986, he retired after 27 years service. His final appointment was as Controller, BP Exploration.

He leaves a wife, two children and a grandchild.

Dr Anthony Denton CBE

It is with regret that we announce the death of Dr Tony Denton, the co-creator of the Noble Denton group.

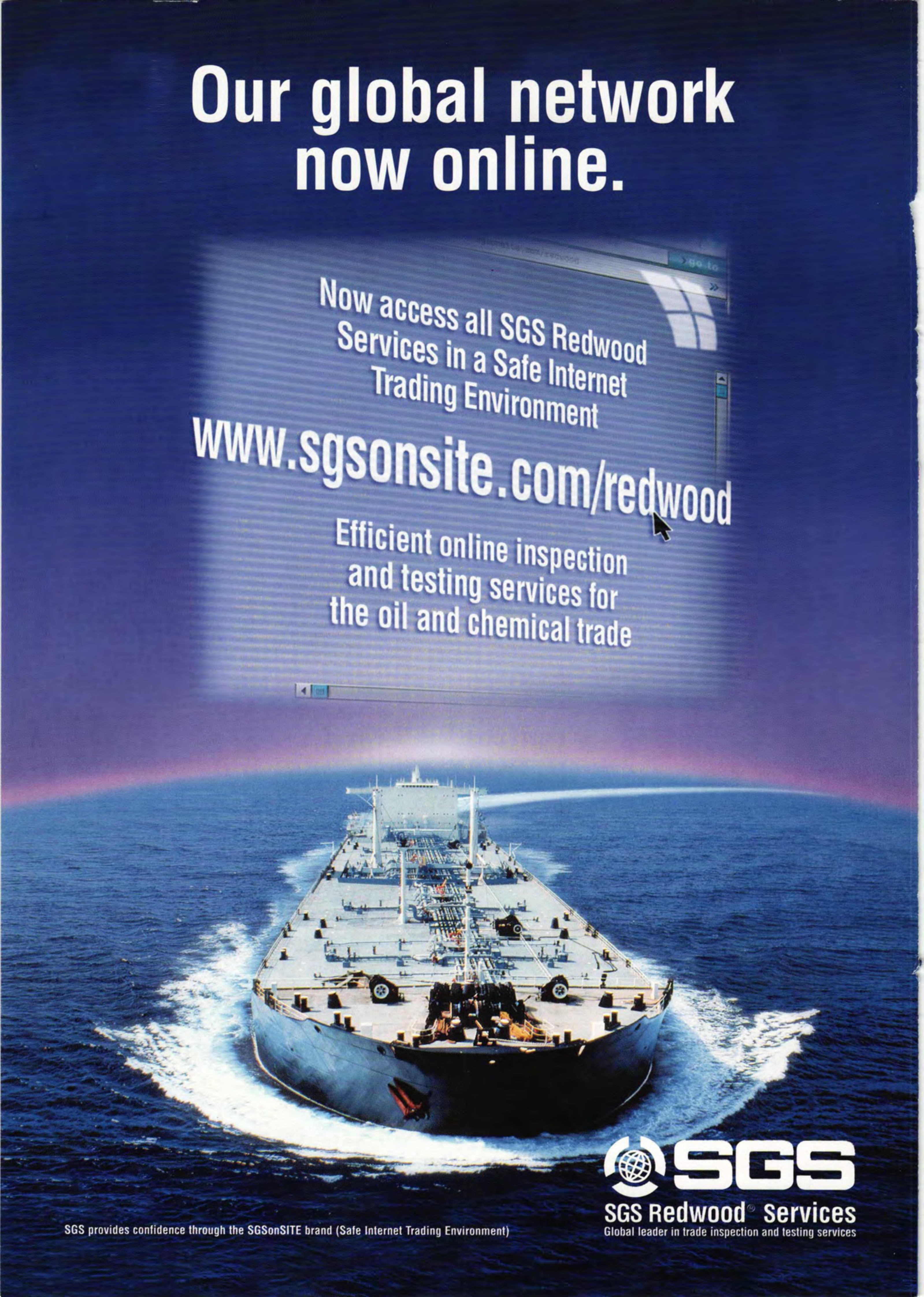
Denton provided the engineering back-up in a partnership that became a significant force in the offshore energy and marine industries, becoming Noble Denton International. He became Managing Director in 1977, and Chairman in 1981.

He was involved in many significant strides in offshore development, including the earliest trans-oceanic towages of mobile drilling platforms and he was on board the first platform to drill in the North Sea.

In addition, he was a Fellow of the Royal Academy of Engineering, of which he was Vice President in 1992–1995, and President of the Institute of Mechanical Engineers in 1993–1994. He also held a Fellowship in the Royal Institution of Naval Architects, The City and Guilds of London Institute and the Institute of Directors. He was awarded a CBE for Services to Engineering in 1997.

He retired as Chairman of the Noble Denton Group in 1997, and until shortly before his death was active as a senior consultant, particularly in marine litigation cases.

He will be missed by all who knew him.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