Petroleum review

AUGUST 2003

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover: Tepsa's bulk storage facility, Bilbao, Spain. For this year's review, turn to p14

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ROUNDUP From the Editor

New perspectives – New challenges

This is the first edition of *Petroleum Review* to be published by the newly formed Energy Institute. It seems a good point to try and take a slightly different perspective on a number of current energy challenges.

For some years there has been a somewhat sterile debate in which alternative energies are promoted as superior to hydrocarbon-derived energy and, further, that the sooner hydrocarbon energy use can be minimised the better. The debate (such as it is) is sterile because all forms of economic development depend on the ready availability of affordable, safe and easy to use energy.

In a truly profound sense all energy sources are complimentary, and all have advantages and disadvantages. Similarly, all forms of energy have applications and markets that they are most appropriate for. Being an Energy Institute should allow this range and diversity to be better addressed.

The need to diversify energy sources and commercialise some of the alternatives is not a luxury but a necessity as the progressive impact of depletion reduces the ability of oil to supply incremental energy demand. The last three years of zero oil demand growth has tended to mask this underlying pressure.

If you tackle a major international oil company about oil depletion and its likely impact, they tend to view it as a distant problem and then focus on their recent exploration success and the new projects that they have in train.

If, however, you talk to people from national oil companies, they will freely tell you of the problems of maintaining production. Of how all the cheap and easy oil has already been found (there are obvious exceptions).

The simple explanation for these almost opposite beliefs is that national oil companies' operations are largely constrained within national boundaries. As a result they are directly confronted by the problems of production decline. In contrast, the big international companies simply sell their declining assets and move to pastures new. So far there have been enough 'new pastures' to support this strategy. Increasingly, however, serious commentators and analysts are starting to ask if this can, in fact, continue without another round of predatory takeovers, significantly higher oil prices or the discovery of some new (and very unexpected) oil province or system.

In the UK the first manifestations of production decline are starting to come through as the country is set to become a net gas importer from 2005/2006 and a net oil importer from 2006/2007.

The Institute of Petroleum (now the Energy Institute) recently hosted a one-day conference on 'Securing the Future of Energy – A Commercial Perspective', organised in association with Ashurst Morris Crisp, which addressed UK concerns about the availability and security of gas imports, the impact of the recent government Energy White Paper, the impact of seeking to minimise carbon emissions, and the viability of alternatives. The limits to sustainability for oil products was also examined. While there was great confidence that the adaptation to being an energy importer would not create any major problems, there was concern about longer-term energy availability and security of supply.

The *BP Statistical Review* probably remains the most widely used source for oil production (or, more accurately, oil and liquids production). By re-arranging the BP statistics into countries where production is declining and those where it is expanding we gain a whole new perspective. In the table on the opposite page the BP production data has been rearranged in this way and listed in descending order of production magnitude. A small increase or decrease from a large producer has much greater overall impact than spectacular growth or decline from a very small producer. (Data from the smaller producers should be treated with some care as a single discovery or start of field decline can determine the direction of the whole country's production.)

We can clearly see that already over one-third of the world's production is coming from countries where decline is established. We can also readily identify the new production stars – Russia, Brazil, Kazakhstan and Azerbaijan. But listing by size immediately shows that at the moment Russia is eight times as important as Kazakhstan and Azerbaijan.

Detailed knowledge tells us that production growth is becoming harder in India, Ecuador, China etc etc, while the Danish Government assures us that its production will be in decline within two

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

e-world

UK Trade and Industry Secretary Patricia Hewitt has launched a new Sustainable Energy Policy Network (SEPN) website, claimed to offer a new transparent and accountable way of working for government, at **www.dti.gov.uk/sepn** The site brings government departments and other key organisations together to coordinate and push forward the policies and programmes needed to ensure delivery of the commitments set out in the Energy White Paper.

The UK Environment Agency's National Groundwater & Contaminated Land Centre has published the second edition of the Groundwater Source Protection Zones (SPZs) that can be downloaded, free of charge, at **www.environment-agency.gov.uk/yourenv/**

Bill Prindle, Deputy Director of the American Council for an Energy-Efficient Economy (ACEEE), testifying before the House Subcommittee on Energy and Minerals, stated that energy efficiency and conservation are the nation's best near-term response to looming crises in natural gas supply and prices. His comments – a summary of which can be viewed at **www.aceee.org/energy/natlgas.htm** – included citation of a list of 15 natural gas efficiency measures that collectively could reduce US gas demand by more than 10% by 2020.

The UK Office of Science and Technology's Foresight Directorate has produced an online newsletter – *e-Sight* – that is to be updated every quarter and will cover developments in the Foresight programme and individual project updates. For more details, visit **www. foresight.gov.uk**

Control Risks Group has launched CR*Travel*Tracker – a web-based international travel tracking service developed to enable companies to take greater responsibility for their employees' travel security. Visit **www.crg.com/crtraveltracker** to obtain more information.

Busy professionals can now quickly and easily test and enhance their understanding of sustainability issues thanks to an electronic tutorial on the business case for sustainable development launched by the World Business Council for Sustainable Development (WBCSD) and the University of Cambridge Programme for Industry (CPI).

Accessible on the Internet at **www.sdchronos.org** Chronos is designed to make sustainable development relevant and meaningful to the everyday practice of employees, equipping them with the knowledge to deliver on corporate priorities.

	Decline from	1995	1996	1997	1998	1999	2000	2001	2002	Change 2002 over 2001	% Change* 2002 over 1997
Producers in Decline*											
US	1985	8,322	8,295	8,269	8,011	7,731	7,733	7,670	7,698	0.30%	-6.91
Norway	2001	2,903	3,233	3,280	3,139	3,139	3,346	3,418	3,330	-3.00%	1.52
UK	1999	2,749	2,735	2,702	2,793	2,893	2,657	2,476	2,463	-0.60%	-8.85
Indonesia	1996	1,578	1,580	1,557	1,520	1,408	1,456	1,389	1,278	-8.10%	-17.92
Oman	2001	868	897	909	905	911	959	961	902	-6.20%	-0.77
Egypt	1993	924	894	873	857	827	781	758	751	-1.00%	-13.97
Argentina	1998	758	823	877	890	847	818	827	800	-3.20%	-8.78
Australia	2000	583	610	668	644	577	812	733	730	-1.00%	9.28
Colombia	1999	591	635	667	775	838	711	627	601	-4.20%	-9.90
Qatar	2000	461	568	694	747	724	796	779	755	-3.30%	8.79
Syria	1995	601	591	582	580	583	554	587	576	-1.90%	-1.03
Other Europe/Eurasia	1992	576	548	526	507	475	468	467	480	3.10%	-8.75
Gabon	1996	356	365	364	337	340	327	301	295	-2.00%	-18.96
Congo (Brazz)	1999	180	200	225	264	293	275	271	258	-4.70%	14.67
Rumania	1985	145	142	141	137	133	131	130	127	-2.30%	-9.93
Peru	1994	123	121	120	119	110	104	98	98	0.00%	-18.33
Cameroon	1997	106	110	124	105	95	88	80	72	-9.90%	-41.94
Papua New Guinea	1993	100	106	76	81	88	69	58	46	-20.70%	-39.47
Tunisia	1992	90	89	81	85	86	80	73	76	3.30%	-6.17
Other Middle East	1992	52	50	50	49	48	49	49	49	0.00%	-2.00
Total decliners		**22,014**	**22,542**	**22,735**	**22,496**	**22,098**	**22,165**	**21,703**	**21,336**	**-1.69%**	**-6.15**
Opec producers with growth potential											
Saudi Arabia		9,032	9,180	9,361	9,370	8,694	9,297	8,992	8,680	-3.70%	-7.27
Iran		3,695	3,709	3,726	3,803	3,550	3,766	3,680	3,366	-8.60%	-9.66
Venezuela		2,959	3,137	3,321	3,510	3,248	3,321	3,210	2,942	-8.30%	-11.41
UAE		2,410	2,495	2,490	2,556	2,299	2,492	2,429	2,270	-6.90%	-8.84
Kuwait		2,130	2,129	2,137	2,176	2,000	2,105	2,069	1,871	-9.80%	-12.45
Nigeria		1,998	2,138	2,303	2,163	2,028	2,104	2,199	2,013	-8.50%	-12.59
Iraq		530	580	1,166	2,126	2,541	2,583	2,371	2,030	-14.40%	74.10
Algeria		1,327	1,386	1,421	1,461	1,515	1,579	1,562	1,659	6.70%	16.75
Libya		1,439	1,452	1,489	1,480	1,425	1,475	1,425	1,376	-3.50%	-7.59
Total Opec growth		**25,520**	**26,206**	**27,414**	**28,645**	**27,300**	**28,722**	**27,937**	**26,207**	**-6.19%**	**-4.40**
Non-Opec producers growing output											
Russian Federation		6,288	6,114	6,227	6,169	6,178	6,536	7,056	7,698	9.10%	23.62
China		2,989	3,170	3,211	3,212	3,213	3,252	3,306	3,387	2.50%	5.48
Mexico		3,065	3,277	3,410	3,499	3,343	3,450	3,560	3,585	1.00%	5.13
Canada		2,402	2,480	2,588	2,672	2,604	2,721	2,712	2,880	6.40%	11.28
Brazil		718	807	868	1,003	1,133	1,268	1,337	1,500	12.20%	72.81
Kazakhstan		434	474	536	537	631	744	836	989	17.80%	84.51
Angola		633	716	741	731	745	746	742	905	22.00%	22.13
Malaysia		724	736	764	815	791	791	786	833	5.60%	9.03
India		804	778	800	791	788	780	779	793	2.00%	-0.88
Yemen		351	357	375	380	405	450	471	473	0.40%	26.13
Ecuador		395	393	397	384	382	409	416	410	-1.50%	3.27
Denmark		188	207	233	235	301	364	347	371	7.00%	59.23
Vietnam		155	179	205	245	296	328	350	354	1.00%	72.68
Azerbaijan		185	183	185	230	278	281	300	308	2.80%	66.49
Equatorial Guinea		7	17	60	83	100	113	181	237	31.00%	295.00
Sudan		2	5	9	12	63	174	211	233	10.40%	2488.89
Brunei		175	165	163	157	182	193	203	210	3.50%	28.83
Thailand		87	97	116	121	132	164	174	197	13.40%	69.83
Turkmenistan		84	90	108	129	143	144	162	182	12.40%	68.52
Uzbekistan		172	174	182	191	191	177	171	171	0.30%	-6.04
Other Asia-Pacific		136	145	158	143	137	136	144	160	10.90%	1.27
Trinidad & Tobago		142	141	135	134	141	138	135	155	15.40%	14.81
Other South America		96	102	108	125	122	129	138	148	7.70%	37.04
Italy		101	104	114	108	96	88	79	103	29.80%	-9.65
Other Africa		51	62	64	63	56	61	64	61	-4.80%	-4.69
Total non-Opec growth		**20,384**	**20,973**	**21,757**	**22,169**	**22,451**	**23,637**	**24,660**	**26,343**	**6.82**	**21.08**
Regional Totals											
Total North America		13,789	14,052	14,267	14,182	13,678	13,904	13,942	14,163	1.70%	-0.73
Total South America		5,782	6,159	6,493	6,940	6,822	6,898	6,788	6,654	-2.10%	2.48
Total Europe/Eurasia		13,825	14,004	14,233	14,175	14,458	14,937	15,443	16,222	5.00%	13.97
Total Middle East		20,130	20,555	21,488	22,692	21,755	23,051	22,388	20,973	-6.50%	-2.40
Total Africa		7,112	7,434	7,754	7,640	7,574	7,803	7,868	7,937	0.80%	2.36
Total Asia-Pacific		7,330	7,566	7,718	7,729	7,612	7,981	7,921	7,987	0.70%	3.49
Total World		**67,968**	**69,770**	**71,953**	**73,357**	**71,898**	**74,574**	**74,350**	**73,935**	**-0.70%**	**2.75**
OECD		20,742	21,352	21,669	21,482	21,040	21,517	21,341	21,516	0.80%	-0.71
OPEC		7,559	28,354	29,663	30,910	29,432	30,974	30,105	28,240	-6.40%	-4.80
non-Opec		33,113	34,245	34,913	35,056	34,915	35,587	35,586	36,214	1.80%	3.73
FSU		7,297	7,171	7,377	7,391	7,551	8,013	8,659	9,482	9.40%	28.53

Source: BP Statistical Review June 2003: Petroleum Review *re-presentation* * Petroleum Review *calculated*

World oil and liquids production 1995-2002

UK offshore Working Time Directive

The UK Government has extended the Working Time Directive to offshore oil and gas workers; non-mobile workers in the road, rail, air and sea transport sectors; mobile workers in the rail and non-HGV road transport sectors; and (to be phased in) for trainee doctors. Such workers will now be entitled to an average 48-hour working week over a 12-month period, rest breaks, health assessments for night workers, and an eight-hour limit on night working. The other groups covered by the announcement will be entitled to four weeks' paid holiday a year – but this is an area that still has to be resolved for offshore oil and gas industry workers.

Commenting on the announcement, Bill Murray, Chief Executive of the Offshore Contractors Association (OCA), said that: 'The industry is pleased that the amended regulations acknowledge the unique working environment offshore in allowing companies to calculate "working time" over a 52-week reference period.' He went on to state that while the government 'was clearly not able to reach a legislative solution or to offer definitive guidance on the application of the fours weeks' paid holiday to the offshore sector... the industry has always been clear that the current work cycles already accommodate four weeks annual leave and that, moreover, the total number of hours worked offshore is well within the maximum permitted by the European directive.'

Meanwhile, Aberdeen Central Labour MP Frank Doran blamed the oil industry for failing to reach a compromise and insisted Ministers tried 'right up to the last minute' to obtain agreement. 'The oil industry made it clear they were not prepared to concede the holidays issue,' he said, adding that he believed the government would propose two weeks' paid holiday. Jake Molloy, General Secretary of the Offshore Industry Liaison Committee, said it was a 'dark day' for offshore workers. 'The fight is not yet over,' he vowed. 'We will fight this through every and any means.'

Statoil takes stakes in Algerian fields

BP is to sell a portion of its Algerian interests to Statoil for $740mn in cash. The sale comprises 50% of BP's stake in the In Amenas gas condensate project and a 49% interest in the In Salah gas project. Following the sale both BP and Statoil will jointly operate the projects with Algeria's state oil and gas company Sonatrach.

The In Salah project is due onstream in 2004 and includes the development of seven proven gas fields, gas processing facilities at Krechba and pipeline infrastructure stretching 579 km north to Hassi R'Mel. The project is expected to produce 9bn cm/y of dry gas. Sonatrach, BP and Statoil are to market gas until the end of a contract of association in 2027. Gas sales contracts are in place with Enel for 4bn cm/y through to 2017, and with Sonatrach for 5bn cm/y through to 2019.

The In Amenas project, at present the largest wet gas joint development project in Algeria, includes the development of four primary gas fields and gas gathering/processing facilities. Due onstream in 2005, it is expected to produce 9bn cm/y of gas and some 60,000 b/d of liquids. Gas will be transported via pipeline to Hassi R/Mel and from there to the ports of Arzew, Isser and Skikda, or via export pipelines routed directly from Hassi R'Mel to Spain and Italy respectively.

Malaysia and Brunei in offshore dispute

Malaysia is reported to have suggested a joint development area type solution in settlement of an ongoing dispute between it and Brunei regarding sovereignty over an oil field straddling the two countries' Exclusive Economic Zones (EEZ). The dispute arose following the discovery of oil offshore the coast of Sabah by Malaysia's state-owned Petronas in July 2002. The Kikeh field has estimated reserves of up to 700mn barrels, equivalent to 21% of Malaysia's current oil reserves.

Both countries contracted prospectors to explore two nearby blocks, and it was discovered that the Kikeh field extends into Brunei's concession area. Malaysia then went on to award a contract to develop Kikeh to Murphy Oil and Petronas Carigali, while Brunei awarded one of the nearby blocks to a Total-led consortium and entered negotiations with Shell regarding the second block.

Both sides have now suspended work until the dispute is resolved. Malaysia is expected to run out of oil in 15 years at current production levels – Kikeh would help arrest this decline.

In Brief

UK

***Total has announced a 'significant' gas** and condensate discovery on the West Franklin prospect in block 29/5b in the central North Sea. The well flowed at 1mn cm/d of gas, with 2,000 b/d of condensate. At 5,750 metres depth the discovery is one of the deepest ever achieved on the UK Continental Shelf, reports Total. It will be put into production from the adjacent Franklin facilities.*

***The fortunes of Edinburgh Oil and Gas** (EOG) have been transformed following the announcement that it has discovered a 30-mn barrel prospect next to the giant North Sea Buzzard oil field.**

***The UK Department of Trade and** Industry is making two blocks in the UK sector of the Irish Sea available for bid. Blocks 113/21 and 113/22 are on offer for an initial term of four years. Applications must be received by the DTI by 16 September 2003.*

Europe

***Danish company DONG has further** strengthened its portfolio in Norway with the acquisition of Agip's 40% stake in licence PL239, also taking over the operatorship, and Shell's 10% interest in licence PL256.*

***ChevronTexaco's Upstream Europe** business unit is selling its equity in three producing fields in the North Sea. The company's net share of production from the Galley, Orwell and Statfjørd fields totals approximately 21,500 boe/d.*

Complete news update

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

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

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www.petroleum.co.uk

NEWS Upstream

West–East China pipeline ahead of schedule

The 1,400-km eastern section of China's West–East gas pipeline project is due to be put into production on 1 October 2003 – two months ahead of schedule – with full commercial operation to commence in January 2004. The 4,000-km cross-China pipeline will transport some 12bn cm/y of gas from the remote Xinjiang Uygur Autonomous Region to Shanghai as part of the government's drive to develop the economy of remote western China. Work on the whole pipeline is slated to complete in January 2005.

Negotiations are reported to be ongoing between PetroChina and the consortium of foreign partners – including Shell, ExxonMobil and Gazprom – regarding the joint venture. It was planned that each of the foreign players would take a 15% in the project, including the development of the gas fields at Shaanxi and pipeline construction.

PetroChina is understood to be planning to soon sign take-or-pay supply contracts with Shanghai Natural Gas Grid and Yangzi-BASF, each taking about 2.5bn cm/y of gas. The contracts are claimed to be the first of their kind in China. The company has already signed non-binding supply contracts with some 45 gas users, with a combined demand of 16bn cm.

Rebuilding Iraqi oil

The US Government is understood to have invited proposals from contractors for one or two contracts worth up to $500mn each to rehabilitate the Iraqi oil sector and restore production to a pre-war level of 3mn b/d. The contract(s) will be 'indefinite delivery, indefinite quantity' agreements lasting for two years, with three one-year options.

The US Administration is reported to prefer to issue two separate contracts, assigned to support Iraq's North Oil (NOC) and South Oil (SOC), with no geographical overlap. The contract(s) will replace the US Army Corps of Engineers' current contract with Halliburton subsidiary Kellogg Brown and Root (KBR), which recently came under scrutiny in US Congress as it was awarded directly without a competitive tender. Proposals from interested parties are to be submitted by 14 August 2003.

North Sea asset changes

Premier Oil is to acquire from Reach Exploration a 50% stake in licence P1048 in Moray Firth blocks 20/10b, 21/6a, 20/15a and 21/11b. The licence is on trend with the Buzzard discovery. Reach will retain a 5% carried interest, having also farmed out a 30% stake to Intrepid Energy North Sea and a 15% interest to First Oil Expro.

Premier has also sold some non-core UK assets to Atlantic Petroleum UK for £8.2mn in cash, £3mn of which will be made up of deferred payments linked to first oil from the discoveries. The package includes a 3.75% stake in the Rob Roy, Ivanhoe and Hamish fields; a 3.75% interest in the Perth discovery in block 15/21 near the Scott and Telford fields; a 15% stake in the Chestnut field and an 11.03% interest in block 20/2 that includes Premier's 8.27% interest in the Ettrick field.

Uplift probability maps for PDO

GAF of Germany has been awarded a contract by Petroleum Development Oman (PDO) to generate uplift probability maps (UPMs) for PDO's 113,000-km concession area in Oman. Based on remote sensing and ancillary data UPM is a new operational exploration tool for the detection of potential hydrocarbon traps in the subsurface. The technology has been developed by GAF within the framework of the European Space Agency (ESA) Earth Observation Market Development (EOMD) initiative and in close cooperation with PDO, a major oil and gas company in the Middle East.

UPM is a customised information product designed specifically for onshore sedimentary basins with a significant role of salt tectonics. It uses a set of geological and geomorphological surface indicators derived from Earth Observation and limited field survey data to delineate hydrocarbon exploration targets. The product is tailored to the needs of the oil and gas industry, and delivers a final digital probability map as well as a structured spatial database of well-defined geological and geomorphological information layers. The technology is specifically designed for first level, frontier exploration in poorly explored regions and for assistance in the reinterpretation of seismic data suffering from quality problems.

In Brief

***The Danish Energy Agency (DEA) has** approved a new venture at the Halfdan field that is forecast to boost the country's gas and condensate reserves by 40mn boe.**

***A 7.9 per cent holding in the Tyrihans** field on the Halten Bank in the Norwegian Sea has been sold by Statoil to Norsk Agip.*

***Astral Petroleum has signed an off**shore oil and gas exploration agreement and production sharing contract with the Government of Malta covering blocks 4 and 5 offshore the east coast. At least four drillable prospects have been identified, along with multiple other leads and prospects.*

***The Norwegian Petroleum Directorate** is reported to have cut its estimate of total oil and gas on Norway's Continental Shelf by 7% to 12.8bn cmoe in a recently published report. The NPD has also reduced its expectations for improved gas recovery from the Shelf.*

***OMV has completed the €300mn** acquisition of the entire international exploration and production portfolio that it obtained from Preussag Energie with effect from 1 January 2003.**

***Aberdeen-based Ramco Energy has** raised £3.9mn through an institutional placing of 1.29mn new ordinary shares. The additional capital will be used to fund the accelerated exploration programme of the Ulcinj block offshore Montenegro with 60% partner Hellenic Petroleum of Greece.*

Eastern Europe

***Turkish Oil Corporation (TPAO) has** signed an agreement with BP to search for oil in the Black Sea.**

North America

***EnCana has closed the sale of its** remaining 3.75% interest in the Syncrude project to Canadian Oil Sands for C$417mn. The company sold an initial 10% stake in Syncrude in February 2003 to Canadian Oil Sands for $1.070bn.**

***Alaska state officials are reported to** have reached an accord with the Bristol Bay Native Corporation over the prospects of opening the first lease sale in the region in more than a decade.*

UKCS oil output falls below 2mn barrels

North Sea oil production fell to 1.9mn b/d in April 2003, down from 2.1mn b/d the previous month and down from 2.2mn b/d in April 2002, according to the latest Royal Bank of Scotland *Oil & Gas Index.* Gas production fell from 11,794mn cf/d in March 2003 to 11,143mn cf/d in April 2003, down from 11,175mn cf/d a year earlier.

The report also indicates that UK oil revenues are being helped by high oil prices, which are being held up by low levels of stocks and delays in the return of Iraq's oil production to the world market. In response, Opec decided to leave production quotas unchanged at its 11 June meeting, noting that markets remained well supplied. Opec expects global stocks to increase in the third quarter of this year. The price of oil has remained above market expectations with Brent crude averaging $27.35/b in June.

'Oil prices have remained high, despite widely held expectations that they would fall following the end of the war in Iraq,' commented Tony Wood, Senior Economist. 'Low levels of global oil stocks is the main factor driving higher prices. Opec's actions, combined with the rate of recovery in Iraq's oil production, will be the two main factors influencing prices over the coming months.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Apr	2,230,781	11,175	25.70
May	2,106,088	10,227	25.50
Jun	2,142,356	9,128	24.10
Jul	1,938,677	7,569	25.70
Aug	1,831,386	8,744	28.40
Sep	2,001,329	8,699	28.40
Oct	2,133,641	10,611	27.60
Nov	2,165,277	11,276	24.20
Dec	2,230,434	12,175	28.30
Jan 2003	2,133,139	12,200	31.20
Feb	2,062,937	12,949	32.20
Mar	2,078,692	11,794	29.90
Apr	1,916,150	11,143	27.50

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Regal takes stake in Eurotech assets

Regal Petroleum has signed a Heads of Agreement to acquire 90% of the entire issued share capital of Eurotech Services for a total consideration to be satisfied by the issue of up to 5mn ordinary shares of 5 pence each in the capital of the company. Eurotech is a private company incorporated in Greece, which owns 67% of the entire issue share capital of Kavala Oil, an oil producer in the North Agean Sea.

Kavala has the exclusive right to exploit and develop three oil fields with proven reserves in the North Agean Sea – Prinos and Prinos North (proven and probable reserves of 310mn barrels) and Epsilon (50mn barrels) – and one exploration and development field, Kallirachi (expected to contain more than 280mn barrels of oil in place and in excess of 96mn barrels of recoverable oil).

Shell sells North Sea package to Talisman

Shell has agreed to sell its non-operated 41.02564% equity interests in the producing Montrose, Arbroath and Arkwright fields (collectively known as 'MonArb'), together with its 10% stake in the Foinaven East field and 2.5% interest in the Magnus Area fields (Magnus, Magnus South) plus associated infrastructure, to Energy North Sea (ENS) for an undisclosed cash consideration.

The oil major has also agreed to sell to Talisman North Sea, for an undisclosed cash sum, its non-operated equity interests in the Alba, Caledonia and Orion producing fields, along with exploration acreage in blocks 15/19a, 15/28a, 15/28b, 16/18a, 16/23N, 16/26 and 30/18W.

In Brief

The state hopes to open onshore lease sales for shallow natural gas by next year and follow that with oil and gas lease sales by the fall of 2005.

***Kerr-McGee affiliates** Kerr-McGee Bahamas and Atlantic Exploration and Production have acquired 100% interests in nine oil and gas licences offshore the Bahamas in the Blake Plateau.*

***Shell has sold 26 of its mature oil and** gas assets in the shallow waters of the US Gulf of Mexico. US independent Apache paid $200mn for assets and the future production of oil and natural gas, while Morgan Stanley, the US investment bank, paid $300mn for the first four years of the fields' oil and gas production.*

***NiSource is reportedly planning to sell** its Columbia Energy Resources exploration and production subsidiary to Morgan Stanley Capital Partners affiliate Triana Energy Holdings for $330mn. Columbia Natural Resources holds 1tn cf of gas reserves in the Appalachian Basin of the eastern US. Under the deal, Triana is also to deliver the 94bn cf of gas remaining under Columbia's forward sales contracts through 2006.*

***TGS-Nopec is to acquire new, non-**exclusive 2D seismic data for Greenland's 2004 licensing round, due to open on 1 April 2004. The closing date for applications will be 1 October that year, with licences expected to be granted in the New Year.**

***BHP Billiton has made an oil discovery** at its second exploration well on the Chinook prospect in the ultra-deep-water Gulf of Mexico.**

***Unocal is to acquire a 45% stake in** the Gulf of Mexico Spirit Energy 76 oil and gas development for $252mn.*

***Barbados is stepping up its search for** oil to raise productivity and cushion the impact of higher prices. A $7.5mn oil exploration programme is expected to boost domestic output to about 1,500 b/d, from the present level of 1,000 barrels, and also raise natural gas production.*

***Imperial Oil is developing plans for a** major new oil sands project that equals its current production of bitumen and synthetic crude. Imperial, already producing nearly 200,000 b/d from its stand alone project and its share of Syncrude Canada's opera-*

In Brief

tions, has said it is now considering a new facility at Kearl Lake, about 60 km north of Fort McMurray, Alta.

***Talisman Energy is expanding its international** portfolio with a deal to explore for oil in Alaska's North Slope. The Calgary-based company has announced an agreement with a unit of French oil giant Total covering 10 blocks of land in the National Petroleum Reserve in northwestern Alaska.*

***Canada has taken a major step forward** in plans for the Mackenzie Gas Project, a $5bn natural gas pipeline that would compete with a similar, but larger, project in Alaska. Imperial Oil Resources has announced that it has completed a funding package that would allow it to submit the plan to Canadian regulators, who were expected to give a green light to the ambitious project.**

Middle East

***Shell (40%) and Total (30%) have** signed an agreement with the Government of Saudi Arabia to form a joint venture with Saudi Aramco (30%) for the exploration of gas in an area of 200,000 sq km in the southern part of the Rub Al-Khali (the 'Empty Quarter').**

***Kuwait's newly appointed Prime** Minister Sheikh Ahmed Al Fahd Al Sabah is expected to head the Energy Ministry and push hard for the re-admission of foreign oil companies into the Emirate.*

***Saudi Arabia has announced discov**eries of oil and natural gas deposits in the central and southeastern regions which flowed at 1.27mn cm/d of sweet gas and 2,050 b/d of oil. The main discovery of 1.13mn cm of gas was made at a well in the Abqaiq field, in the southeast of the kingdom. More production is expected from the same area based on initial tests.*

***Iran is claiming a major new oil find** containing estimated reserves of more than 38bn barrels. Preliminary studies indicate that the Ferdows field contains 30.6bn barrels, the Mound field 6.63bn and the Zagheh field 1.3bn.*

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NEWS Upstream

Latest oil and gas news from Africa

Stella Zenkovich reports on recent upstream developments in Africa:

- Lukoil of Russia has signed two new oil concession agreements, with estimated reserves totalling 423.8mn barrels, with the Egyptian Oil Ministry and has pledged to invest $26.1mn on exploration. Already sole operator of a third concession – the Eastern Desert concession – Lukoil will be sole operator of the new West Geisum and North-East Geisum blocks, both located in the offshore Gulf of Suez. The company jointly operates the Western Desert concession with Agip.
- Namibia's long-stalled Kudu gas field development project will finally get the go-ahead by the end of the year following a switch in anchor customers from a South African power plant to a 800-MW gas-fired station in Namibia itself. The Kudu joint venture of Energy Africa (40%) and ChevronTexaco (60%) recently finished technical analysis that is reported to prove that reserves are more than ample to keep an 800-MW plant operational for over 20 years and to supply South Africa.
- US-based Forrest Oil and local partner Petro have made a gas find in South Africa's offshore Idhubeshi field, north of Saldanha Bay. Estimated reserves are put at 13tn cf. Forrest's plan for the next seven years calls for three combined-cycle gas turbine power stations at Cape Town, Mossel Bay and Saldanha, a GTL plant at the latter facility, and hundreds of kilometres of subsea and overland pipelines to convey gas to the southern Cape.
- US-based Vanco Petroleum International is planning to start drilling for oil offshore the Moroccan city of Essaouire in the Atlantic, having earmarked $20mn for exploration there. It is Vanco's second Moroccan offshore contract; the company signed the first in 2002 for exploration near northern Aghadir.
- Repsol of Spain, Oranto Petroleum of Nigeria and 8 Investments of the US have submitted bids for the Sierra Leone Government's offer of seven offshore blocks covering 28,000 sq km.
- Petronas, the Malaysian state oil company, has signed five-year oil exploration and production agreements with the Ethiopian Government covering 15,356 km of the southwestern Gambela block and a part of the eastern Ogaden Basin, near the border with Somalia.
- Edison of Italy has made a new Egyptian gas find, the Rashid North off the Nile Delta's Rosetta concession. The Rosetta-11 exploratory well may be reused in the production phase.
- Eni is reported to be on course to bring its $4.6bn Libyan joint venture Wafa onshore gas project onstream in 2004, instead of 2005 as originally planned.

Contract award for Qatargas expansion plans

Qatar Petroleum (70%) and ExxonMobil's (30%) Qatargas II LNG expansion project has agreed to award the main front-end engineering and design (FEED) phase contracts to Chiyoda Corporation for the onshore facilities and M W Kellogg for a receiving terminal. The offshore FEED contract will be awarded later this year.

Qatargas II will include offshore development of new blocks in Qatar's giant North field, the world's largest onshore liquefaction trains each producing about 7.8mn t/y of LNG, a fleet of large LNG carriers and re-gasification/terminal facilities. The LNG onshore facilities will be constructed at the existing Qatargas LNG plant that has been operating since 1996 and where currently three trains are producing over 8mn t/y of LNG. Gas deliveries from the Qatargas II trains, which are targeted for sale in the UK and North Europe, will commence from the first train in late 2007.

According to His Excellency Abdullah bin Hamad Al Attiyah, Minister of Energy & Industry and Chair of Qatar Petroleum: 'Qatargas II is a key element in Qatar's long-term plan of increasing North field monetisation and LNG exports to over 45mn t/y by the year 2010.'

TAGP project well on schedule

The $7bn Trans Asean Gas Pipeline (TAGP) project is being implemented on schedule, with the majority of seven identified routes either operational or under development. The seven gas pipeline interconnecting routes are: Malaysia–Singapore; Yadana and Yetagun (Myanmar)–Ratchaburi (Thailand); West Natuna (Indonesia)–Singapore; Camago–Malampaya in the Philippines; West Natuna–Duyong (Malaysia); Malaysia–Thailand Joint Development Area (JDA); and South Sumatra–Singapore.

Changes to Russian domestic gas taxation

The Russian Duma has approved amendments to domestic gas taxation. According to UFG, the current tax system applied to natural gas differs from that applied to the oil sector and three main taxes are charged:

- **Royalties (or the mineral extraction tax) are levied at a fixed rate of 16.5% of the wellhead price of gas.**
- **Export duty is a straight 5% of the value of exports.**
- **Excise duty is charged at a rate of 15% for sales in Russia and the CIS, and 30% for sales to markets outside the CIS.**

The changes approved by the Duma will bring gas sector taxation closer to that for the oil sector. The draft law proposes abolishing excise duties on natural gas but increasing the mineral extraction tax. Once the law comes into force – it has to be approved by the Federation Council and President – the mineral extraction tax will be Rb107/mn cm for all gas producers.

In a related development, the Duma also approved a 5% increase in the basic rate of mineral extraction tax for crude oil, from Rb340/t to Rb357/t.

Shipping Snøhvit LNG to domestic market

Statoil has issued the shipping industry an invitation to tender for the supply of a new vessel to carry LNG from the Melkøya liquefaction plant outside Hammerfest in northern Norway to reception terminals along the Norwegian coast. The vessel will be chartered by LNG Norge, currently wholly owned by Statoil although the longer-term aim is to involve distributors Naturgass Vest and Gasnor at a later stage, each holding 15% apiece.

Statoil is aiming to establish the commercial feasibility of supplying the domestic market via a small-scale chain of LNG terminals fed from the Snøhvit project in the Barents Sea. Plans call for a decision on commercial operation of LNG Norge in 2Q2004, when the government will present a study on Norwegian gas supply to the Storting (parliament).

Rising Russian output boosts exports

Russian Deputy Prime Minister Victor Khristenko is reported to have stated that Russia will export 3.38mn b/d of crude oil in 3Q2003, equivalent to some 38% of production. The country exported 3.2mn b/d of oil in 2Q2003. This implies that producers are expecting crude production in 3Q2003 to increase by 9% quarter-on-quarter, comments UFG.

Oil production has been aided by a significant increase in Transneft capacity, which, according to Khristenko, was up 300,000 b/d in the first five months of 2003. The capacity expansion primarily affects deliveries to domestic refineries (220,000 b/d), with the balance being exported. The BPS-2 (Baltic Pipeline System, Phase 2) will add another 120,000 b/d in export capacity.

In a related story, Russia's Federal Energy Commission is reported to have agreed to raise Transneft's tariffs by an average of 4.75% from 1 July 2003. The company had applied for the increase as a means of financing the construction of the BPS-2 pipeline. Analyst UFG believes that, unlike the tariff increase of 1999–2001 that was implemented to help fund BPS-1, it is unlikely that this latest increase will be cancelled once Transneft completes the BPS-2 project.

Proposed amendements to Marpol Annex I

The European Union Member States and the European Commission have suggested wide-ranging amendments to Annex I of Marpol 73/78 to:

- **accelerate the current schedule of phasing out single-hulled tankers;**
- **expand the Condition Assessment Scheme (CAS) to all Category 2 and 3 oil tankers over 15 years of age; and**
- **ban the transport of heavy grades of oil in single-hulled tankers.**

The proposals are to be put to before the International Maritime Organisation (IMO) for consideration.

In Brief

UK

***The UK Department of Trade and** Industry (DTI) has released proposals for the next generation of offshore windfarms to provide up to 6 GW of new energy generation by 2010, enough to power 15% of all UK households.**

***Sir John Parker FREng, Chairman of** National Grid Transco, has been awarded the 69th Melchett Medal by the Institute of Energy (now the Energy Institute) for outstanding services to the energy industry.*

***Ofgem and the UK Department of** Trade and Industry (DTI) have set out initial views on a new regulatory framework for all new LNG importation terminals and interconnectors. The proposals anticipate EU legislation to help create a European-wide energy market. They will help give regulatory certainty to developers wishing to build LNG terminals and gas and electricity interconnectors to and from Britain, helping to improve security of supply.*

Europe

***Ireland's Energy Minister Dermot** Ahern reports that Ireland could be producing 70% of its requirement for natural gas by 2007. At present some 80% of gas is imported – but that will change when gas production commences from the Seven Heads field and the Corrib field offshore Co Mayo. Seven Heads is due onstream in October 2003.*

***Mol, the Hungarian oil and gas com**pany, looks poised to win a 25% stake in Ina, its Croatian state-owned counterpart, after outbidding Austrian rival OMV with an offer of $505mn.*

***BG reports that Enel has acquired for** €10.9mn a 50% stake in the proposed €390mn Brindisi LNG import project in Italy. The facility is to be commissioned in early 2004. BG and Enel will share 80% reserved capacity in the proposed terminal equally. The remaining 20% will be subject to regulated third-party access.*

***It is rumoured that ABB is in advanced** talks to sell its oil, gas and petrochemicals unit, worth about $1.4bn, to UK buyout firm Candover Investments. General Electric, Cooper Cameron and*

In Brief

Halliburton have also expressed interest in the ABB unit.

North America

***ChevronTexaco has reached an agreement** in principle with Dynegy to exchange its Series B preferred Dynegy stock for an aggregate of $850mn in cash and new Dynegy securities.*

***The US Federal Energy Regulatory** Commission (FERC) gave the green light to Dominion Resources to receive a single test cargo of LNG at its Cove Point terminal in Maryland in July. The company wants to resume tanker shipments of LNG at the terminal for the first time in 23 years.**

Middle East

***Iran intends to increase its imports** of oil products from Russia and Kazakhstan by 350% to 4.5mn tonnes this year.**

***All eight of the foreign oil majors** involved in Saudi Arabia's failed natural gas initiative (NGI) were among 50 oil companies invited for talks in London during July to discuss restructured gas projects.**

***Two major Iranian oil corporations,** Petropars and Petro Iran, have announced that they will soon merge to form a giant Middle Eastern oil company.*

***BP, Shell, ChevronTexaco and Swiss** trading firm Taurus have all won the right to buy 2mn barrels of Basra Light crude from Iraq in what is believed to be the first sale of crude pumped since the end of the Iraq war.*

***BG Group and Egyptian LNG (ELNG)** Train 2 partners have agreed the principal terms for LNG sale and purchase agreements (SPAs) for the entire 3.6mn t/y output of Train 2 with BG Gas Marketing, a subsidiary of BG Group. The ELNG Train 2 partners have awarded the EPC contract to Bechtel Corporation for the construction of the Train 2 facilities – the $550mn ELNG Train 2 is scheduled to start commercial operations in 2006.*

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UK energy statistics

The UK Department of Trade and Industry recently published its *Energy Trends* and *Quarterly Energy Prices*. Indigenous production of primary fuels is reported to have reached 72.9mn toe in 1Q2003, some 0.2% lower than in the first quarter of 2002, while final energy consumption in the period was 1.9% higher than 1Q2002.

Meanwhile, total inland consumption on a primary fuel input basis was 244.9mn toe in the quarter, down 1.6% on 1Q2002. Between the first quarters of 2002 and 2003 coal and other solid fuel consumption rose by 5.4%, oil consumption decreased by 6.5%, gas consumption fell by 0.8%, and primary electricity consumption decreased by 2%.

Coal production (including an estimate for slurry) was 7.8% down on 1Q2002 at 7.8mnn tonnes, while imports of coal were 0.6% lower at 6.9mn tonnes. Compared with the very high import levels of two years earlier, imports were down by 22.3%. Demand for coal in 1Q2003, at 18.6mn tonnes, was 8.6% up on consumption in 1Q2002. Consumption by electricity generators was up by 12.7%.

Total indigenous UK production of crude oil and NGLs in 1Q2003 decreased by 3.1% compared with 2002 to 28.7mn tonnes. Twelve new fields started up after March 2002 – without these new fields production would have been 7% lower than last year, reports the DTI.

The UK retained its position as a net exporter of oil and oil products. Exports of petroleum products rose by 20.8% whilst imports fell by 6.1%. Overall primary demand for oil products in the period was 3.4% lower than last year. Deliveries of unleaded motor spirit fell by 6.5%. Deliveries of derv fuel were 10.2% lower, while deliveries of aviation turbine fuel increased by 2.8%.

Total indigenous UK production of natural gas in 1Q2003 was 4.6% higher than in the same period a year earlier. Gas exports increased by 64.8%, while imports were 2.3% lower – although within this figure imports from Norway via the Vesterled pipeline nearly doubled. Demand for gas in 1Q2003 was 4.6% higher than the level in 1Q2002.

Gas use for electricity generation was 4.2% lower than in 1Q2002, reflecting the fact that high gas prices meant some generators found it more profitable to sell the gas than use it for generation.

Looking at fuel prices, in mid-June 2002 a litre of unleaded petrol was on average 74.5 p/l, an increase of 0.5 p/l compared to a year ago, while diesel averaged 76.7 p/l, 1.1 p/l higher. Lead replacement petrol (LRP) cost, on average, 79.5 p/l in mid-June 2002. Compared to a year ago this represents an increase of 2.2 p/l.

Crude oil prices have fallen sharply in recent months to levels seen a year ago, reports the DTI. The rise in prices during the year was due to the conflict in the Gulf. Although petrol prices have started to decrease they are still slightly above levels of a year ago. Overall, the price paid for all fuel and light by household consumers has fallen by 0.3% in real terms between Q12002 and Q12003.

A special feature in the June 2003 *Energy Trends* looks at renewable energy in 2002, including summary renewables statistics for 2002 that are published for the first time. A full set of renewables statistics was to appear in the Digest of United Kingdom Energy Statistics, due to be published as *Petroleum Review* went to press. The main features of the latest statistics are:

- Electricity generated from all renewables and wastes as a percentage of total UK electricity generation rose to 3% in 2002. In 2001 it was 2.6%.
- In 2002 the percentage of UK electricity sales that were from sources eligible for the Renewables Obligation (RO) was 1.7%, up from 1.5% in 2001.
- Total electricity generation from all renewable sources in 2002 was 11,444 GWh, 40% of which was from large-scale hydro generation.
- Generation from renewable sources other than large-scale hydro was 10% higher in 2002 than in 2001.
- As at 31 December 2001, 352 projects contracted under the Non Fossil Fuel Obligation (NFFO), the Scottish Renewables Orders (SRO) and the Northern Ireland-NFFO had been commissioned and were generating electricity, with a capacity totalling 985 MW. Total renewables capacity in the UK at that date was 2,565 MW.

Energy Trends and the *Quarterly Energy Prices* bulletins are published quarterly, and are available via the Internet at **www.dti.gov.uk/energy/inform/energy_stats_overview/index.shtml**

Call to refocus UK enviro-friendly fuel tax breaks

Tax breaks intended to favour environmentally friendly fuels do not currently reward those least damaging to the environment, according to the Institute for Public Policy Research (IPPR). In a recently published report it argues that tax incentives should benefit biofuels instead of liquefied petroleum gas (LPG).

Tax breaks for LPG – which costs half the price of petrol at the pump – are expected to cost the UK Government £60mn in lost revenue this year. This is despite the fact that the environmental benefits of LPG have been growing increasingly weak as conventional cars become less polluting, states IPPR. Biofuels, which are derived from woody crops and crops such as rapeseed and sugar beet, produce less greenhouse gases but receive a higher rate of duty than road gas fuels.

Julie Foley, IPPR Transport Research Fellow, said: 'The government has pledged to cut greenhouse emissions by 20% by the end of the decade. It is unlikely to achieve this without a more rational approach to tax breaks and subsidies aimed at encouraging provision of environmentally friendly fuel. The tax break on LPG can no longer be justified on environmental grounds. This needs to be progressively reduced. The government should develop tax incentives which take into account pollution created in production and distribution and place more emphasis on expanding the market for biofuels and hydrogen.'

According to IPPR, developing tax incentives for alternative fuels that better reflect their global warming impact would help to:

- Distinguish and reward lower carbon forms of fuel.
- Send a longer-term price signal of the government's commitment to lower carbon transport fuels.
- Provide a benchmark for comparing the environmental performance of new and emerging fuels.

OMV on target with expansion plans

OMV has completed its €377mn acquisition of 313 Aral and BP service stations in southern Germany, Hungary and the Slovak Republic, together with a 45% stake in the Bayernoil refining network and an 18% stake in the Transalpine Pipeline (TAL). The acquisition, claimed to be the largest in OMV's history to date, brings the company closer to its target of doubling its size by 2008 and of becoming a leading European oil and gas company.

This latest deal places OMV in a leading position in Bavaria and has strengthened its presence in Hungary and the Slovak Republic. The company now operates 1,736 service stations in Central and Eastern Europe, a market share of 12%. It hopes to increase this market share to 20% by 2008.

The deal also increases OMV's refining capacity in Bavaria from 3.4mn t/y to 8.8mn t/y, and takes its total shareholding in TAL to over 25%.

In Brief

UK

***BP is to expand its Scottish retail net**work by acquiring 25 service stations owned by Texaco in the central area of Scotland. The move is part of an asset 'swap' between the two companies that will see Texaco Ltd, a subsidiary of ChevronTexaco, taking over 21 BP sites of equal value in Wales and southwest England.*

***The Microjoule team set a new world** record for fuel economy while winning the 2003 Shell Eco-Marathon, with an astounding average fuel consumption of 10,705 mpg at the Rockingham Motor Speedway in Corby, Northants. The French team beat their previous world fuel consumption record by nearly 500 mpg.*

***Lloyds TSB is to become the latest bank** to launch a credit card for motorists, teaming up with Texaco to offer a new cash-back version. The bank will offer big discounts to motorists on their petrol costs, with rebates of up to 1.6% when they buy fuel or any other item from Texaco shops.*

***UK fuel management company CH** Jones has acquired British Gas' CNG vehicle refuelling business for an undisclosed sum. The business is to be renamed KeyGas. The operation will have a network of 11 multi-user sites and many dedicated facilities.*

Europe

***New analysis from independent** market analyst Datamonitor reveals that less than four years after the Bersani Decree introduced limited competition among Italian electricity suppliers, more than half the country's major energy user (MEU) market has already switched supplier. The preliminary results from Datamonitor's survey of Italian major energy buyers, which covers 20% of the over-1GWh market (by volume), suggest that levels of customer switching in this segment reached 22% in 2002 and will remain equally high over the next 12 months. This will lead to at least another €2.5bn worth of electricity supply contracts changing hands in the over-1GWh segment alone.*

***Statoil and Telenor have launched** wireless Internet zones at 300 Statoil forecourts across Norway. The deployment is claimed to be one of Europe's largest Wi-Fi (wireless fidelity) rollouts,*

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*with Statoil the first major service station operator to offer its customers wireless access.**

Eastern Europe

***Lukoil is reported to be planning to** invest $200mn in Hungary and Moldova over the next two years. It is also to resume production at a 104,000 b/d refinery in Romania in June 2004 that will supply Hungary.*

North America

***Vopak is to acquire Dow Chemical** Company's chemical tank terminal in Long Beach, California, US, for an undisclosed sum. The facility comprises 55 tanks with a total capacity of 56,000 cm.*

***Merrill Lynch & Company has reformed** an oil and natural gas trading group after a two-year absence from energy trading. Merrill exited energy trade in January 2001 when it sold its Global Energy Markets trading unit to Allegheny Energy. The move comes as rival banking firms Goldman Sachs, JP Morgan and UBS have reaped increased profits from bolstering their energy trading operations.*

***Valero Energy has received approval** from a US bankruptcy court to buy a 185,000-b/d Louisiana oil refinery from Orion Refining for $530mn, including fuel inventories. Valero, the third-largest US refiner, will pay $400mn, plus $130mn for inventory and other assets.*

***ExxonMobil is understood to be planning** to build its first LNG terminal in the US, at Sabine Pass in Texas. Together with Qatar Petroleum, the company is to deliver 7.5mn tonnes of LNG to the US.*

Middle East

***British Gas has signed an agreement** to sell up to 500mn cm/y of natural gas from Gaza to the private power station that will be set up by the Uri Dori-Gmul-Eilat Ashkelon Pipeline Company group (Dorad) in Ashkelon. Dorad has obtained the approval of the Israeli National Infrastructure Ministry to build a 400-MW power station, but the Ministry is now discussing the company's request to increase capacity to 800 MW.*

NEWS Downstream

Energy Charter Protocol on Transit

The Energy Secretariat reports that, contrary to expectations, it was not possible to finalise the text of an Energy Charter Protocol on Transit, which has been under negotiation among the Energy Charter's 51 member-states since early 2000, at the 12th Charter Conference in Brussels. The aim of the Transit Protocol, which builds on the existing transit-related provisions of the 1994 Energy Charter Treaty, is to establish an enhanced set of rules under international law governing cross-border flows of energy in transit via inter-state pipelines and grids.

At the last meeting of the Charter Conference in December 2002, agreement was reached that only three issues in the draft text of the Protocol were to be considered as unresolved. These were: the European Union's proposal for a Regional Economic Integration clause; the Russian proposal for a so-called 'Right of First Refusal' for existing transit shippers; and the issue of transit tariffs. Since that time, given that these unresolved issues related primarily to differences in position between the European Union and Russia, efforts have focused on finding solutions to them through bilateral consultations between these two parties, with the aim of developing an overall 'package' text that all delegations could accept.

Although the final text was not agreed at the Conference, agreement was reached on the procedures for taking forward work on the remaining issues, with the aim of achieving a final decision as 'early as possible'.

First LPG shipped from Bonny to US

Nigeria LNG has commenced shipping of LPG from its plant in Bonny, Nigeria, with the LPG/C *Berge Clipper* VLGC (very large gas carrier) setting sale with 40,000 tonnes of refrigerated LPG destined for Galina Park in the US. The shipment was sold on spot basis to Vitol of Switzerland. Subsequent cargoes will be sold on a free on board (FOB) term basis.

NLNG's three trains will produce 1.2mn t/y of LPG when plateau LPG production is reached. The figure will climb to 2.2mn t/y when trains 4 and 5, currently under construction, are commissioned. The plants will also have the capacity to produce 450,000 t/y of condensate.

Partners in NLNG are Nigerian National Petroleum Corporation (49%), Shell (25.6%), Total (15%) and Agip (10.4%).

Concerns over 'Blue diesel' proposals

The UK Petroleum Industry Association (UKPIA), the trade association representing refiners and marketers of fuels in the UK, has asked the UK Government to drop one of its two proposed methods for offsetting the planned distance related Lorry Road User Charge (LRUC) by means of a reduced rate of duty on diesel for heavy goods vehicles (HGVs). Under the proposal to which UKPIA has objected a new duty rebated fuel, chemically marked with a blue dye to distinguish it from other types of diesel and only for use in qualifying HGVs, would need to be introduced to the UK market.

UKPIA strongly favours the government's other proposal for offsetting the LRUC, which would require hauliers to make a retrospective claim for a duty rebate direct to the government. This method would link a duty claim with the amount of the LRUC, providing a system of cross-reference that would be markedly less open to fraud and abuse.

UKPIA has called the 'blue diesel' proposal 'unworkable, costly for the oil industry and an open invitation to fraudsters, likely to exacerbate an already serious level of fraud on existing rebated diesel fuels'.

The concerns stem in part from the experience of a scheme known as Registered Dealers in Controlled Oils (RDCO), which was introduced in 2003 with the aim of reducing the high level of fraud on duty rebated 'red diesel' mainly used in agriculture. It is too early to tell if the scheme has had any appreciable impact on the estimated £450mn/y of lost duty on red diesel but it is clear that the RDCO scheme has already put a considerable administrative burden and hence cost on oil distributors, says UKPIA.

The Association adds that: 'A new duty rebated "blue diesel" will add further significant cost burdens on the industry and it will also greatly increase the scope for fraud because the volumes involved are much higher, there are many more refuelling points for HGVs than for agricultural users and there would be no cross-check between an HGV registered under the LRUC scheme and use of "blue diesel".'

NEWS Downstream

APX acquires EnMO and outlines future plans

Amsterdam Power Exchange Spotmarket (APX) has acquired 100% of the shares in EnMO, formerly owned by National Grid Transco (NGT) of London and Altra Energy Technologies of Houston. Established in 1999 to operate the On-the-day Commodity Market (OCM) as part of the UK's Reform of Gas Trading Arrangements (RGTA), EnMO's Internet trading exchange accounts for approximately two-thirds of all UK within-day gas trading.

According to Bert den Ouden, Chief Executive Officer of APX, the acquisition 'marks a further major step towards our goal of offering the first integrated, international exchange for physical gas and electricity'. The deal follows APX' purchase in February of the UK power exchange APX. APX is also plannning to launch a gas exchange in the Netherlands as possibilities for gas trading emerge. In a parallel move, APX partner Endex will study a gas futures exchange.

Quantum takes stake in UK gas market

Quantum Energy Group has acquired the share capitals of Fortum Energy Plus and Saracen Gas from a subsidiary of the Finnish group Fortum. The deal will create a business that holds approximately 5% of the UK gas supply market serving small and medium sized enterprises (SMEs) and multi-site operators. The combined business will have in excess of 10,000 gas customers with revenues of some £130mn.

A new holding company, Bradbox, has been established as the parent company of Quantum Energy Group. Bradbox is 60% owned by a consortium in which Global Natural Energy is a minority investor and 40% owned by funds managed by Barings Private Equity Partners. Together, these shareholders will inject new equity of £6mn into Bradbox.

Shell GTL fuels 'green' London bus

A London bus running on Shell's new ultra clean fuel has been launched by Green Fuels Minister David Jamieson. Shell, London General and the DaimlerChrysler subsidiary EvoBus (UK) will be trialling the fuel over the next few months on a 507 'bendy bus' running from Waterloo to Victoria stations. A fleet of Volkswagen cars is also currently testing the fuel in Berlin, Germany.

Shell gas-to-liquids (GTL) transport fuel is a synthetic product derived from natural gas rather than crude oil. It is virtually free of sulphur and aromatics, and is claimed to offer significantly lower vehicle emissions of local pollutants such as nitrogen oxide, particulates, carbon monoxide and hydrocarbons than conventional diesel. The gas-derived fuel opens up the possibility of commercialising stranded gas reserves. It can be used in conventional diesel engines without the need for any modification and offers a cost-effective means of reducing local air emissions. The GTL fuel is currently produced on a relatively small scale at Shell's plant in Bintulu, Malaysia. The plant – at present the only commercial GTL facility of its kind in the world – produces 12,500 b/d of transport fuels and speciality products.

In Brief

State-owned Qatar Petroleum has *signed a Letter of Intent with Marathon Petroleum Qatar for the study of a gas-to-liquids (GTL) plant in Qatar. Meanwhile, Venezuela is looking to participate in Qatar General Petroleum Corporation's $2.7bn Mariscal Sucre LNG project.*

Russia & Central Asia

Lukoil has reported that its Lukoil- *Nizhegorodnefteorgsintez subsidiary has started commercial production of Jet A-1 fuel in compliance with the requirements of the International Air Transport Association (IATA). It is to supply the fuel to foreign airlines that operate regular flights to the Russian Federation.*

Petrol and Mol of Hungary have sub- *mitted a joint bid for a 79.5% stake in Serbian fuel retailer Beopetrol, which operates 180 service stations and seven oil product depots.*

Lukoil is understood to be planning to *launch its Petrotel refinery in Romania after an upgrade programme is completed in June 2004. The company bought the refinery in 1998 for $300mn and has spent a further $60mn on refurbishment. An additional $96mn is to be spent on its Romanian service station network, reports UFG.*

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

UK Deliveries into Consumption (tonnes)

Products	†May 2002	†May 2003	†Jan–May 2002	†Jan–May 2003	% Change
Naphtha/LDF	81,481	130,147	432,561	987,102	128
ATF – Kerosene	877,645	841,714	3,927,183	4,078,838	4
Petrol	–	–	–	–	–
of which unleaded	1,713,549	1,626,453	8,248,601	7,909,192	–4
of which Super unleaded	45,607	65,026	216,414	331,417	53
ULSP (ultra low sulfur petrol)	1,667,942	1,561,427	8,032,187	7,577,775	–6
Lead Replacement Petrol (LRP)	61,324	18,475	241,522	96,699	–60
Burning Oil	263,274	268,114	1,831,646	1,620,732	–12
Automotive Diesel	1,422,084	1,461,063	6,952,062	6,844,758	–2
Gas/Diesel Oil	513,624	475,664	2,638,576	2,576,466	–2
Fuel Oil	167,908	157,779	951,816	983,890	3
Lubricating Oil	65,916	68,181	354,047	351,800	–1
Other Products	694,966	639,907	3,425,434	3,444,678	1
Total above	5,861,771	5,707,497	29,003,448	28,914,125	0
Refinery Consumption	370,976	380,275	2,067,789	1,888,276	–9
Total all products	6,232,747	6,087,772	31,071,237	30,802,401	–1

† Revised with adjustments

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

IP Autumn Lunch

22 October 2003

Claridges Hotel
Brook Street, London UK

The IP Autumn Lunch is now an established date in the oil and gas calendar of events. It provides a unique opportunity to hear an internationally renowned figure speak on contemporary global issues relating to our industry.

The Institute of Petroleum is pleased to announce its sixth IP Autumn Lunch with Guest of Honour and Speaker

Dr Alvaro Silva-Calderón
Secretary-General, OPEC

Dr Silva-Calderón obtained a doctorate degree in law and politics from Universidad Central de Venezuela science in 1956. For over 25 years he has been a lecturer at the Law School of Universidad Central de Venezuela, Department of Mining and Hydrocarbons Law. He is also an Emeritus Professor there and has taught in the postgraduate programme on the Economy of Hydrocarbons.

Silva-Calderón started his career as a member of the advisory team of Juan Pablo Pérez Alfonso, and was President of the regional legislature of his home state of Monagas. Subsequently, he was a member of the National Congress, serving as President of the International Treaties Sub-committee and member of the Energy and Mines Committee.

He has been a columnist for national daily newspaper *El Globo* for several years, contributing articles on oil and the impact of oil activities in Venezuela. He is an active member of the Venezuelan Chapter at the World Petroleum Congress, where he has participated as Venezuelan delegate on several occasions.

He is a member of the National Energy Council and was appointed Minister of Energy and Mines of Venezuela in 2000, a position he held until mid-2002. In this capacity, he has actively promoted co-operation within OPEC and with non-OPEC oil producing countries. He was also actively involved in co-ordinating and organising the Second Summit of OPEC Heads of State, held in Caracas in September 2000.

On 1st July 2002, Dr Silva-Calderón was appointed Secretary General of OPEC.

To apply for tickets, please complete this form in BLOCK CAPITALS and return it to the address below, together with payment in full. For further information please contact
Lynda Thwaite, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK.
T: + 44 (0)20 7467 7106, F: + 44 (0)20 7580 2230, e: lthwaite@energyinst.org.uk

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American Express: 3% of the total amount due.

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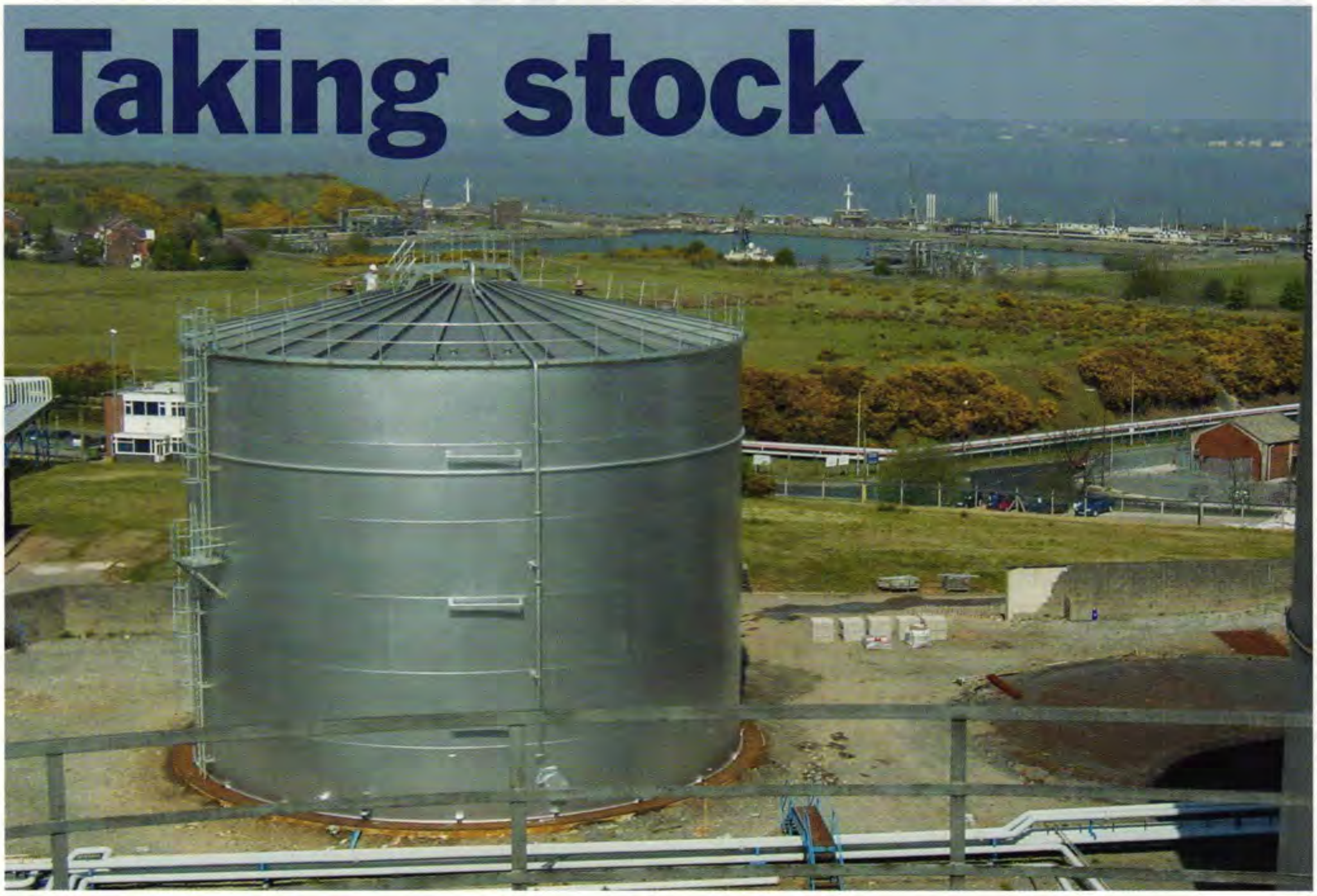
Tickets will be allocated and mailed from the week commencing 1 September 2003.

In the event of cancellation of attendance by ticket purchaser a refund, less 20% administration charge of the total monies due, will be made provided that notice of cancellation is received in writing on or before 29 August 2003. No refunds will be paid, or invoices cancelled after this date.

Taking stock



Business may not be quite as bright as it was a couple of years ago, but with their tanks more or less full on a seemingly permanent basis, operators of independent bulk liquids storage capacity in Europe are hardly in pain either. *Petroleum Review* reports.

New ethylene dichloride tank at ST Services' Eastham terminal

With the oil market reverting to something approaching normality over the past year, the disappearance of the long-running contango in the forward market has reduced the chances of terminal owners picking up business from traders and oil companies holding stock ahead of a price upturn. On the other hand, the broader economic uncertainty and, in particular, the threat to the oil market arising from the build-up to the war in Iraq meant that oil importers have, over the past year, been keen to maintain a good level of buffer stocks.

As a result of this there is very little spare capacity for oil product and petrochemical storage in Europe, especially in northern Europe. Should the EU go ahead with plans it is considering to increase member countries' strategic stock requirement, then the situation could get very tight indeed. Perhaps it is an indication of the current very decent state of business that even the terminal operators themselves are not necessarily supporting this move – they are already doing quite well enough.

Europe vs the world

A year ago this review noted that there was very little actually happening in the European terminal sector. This was partly due to structural effects, notably the hiatus imposed on new business by the spin-off of Univar from Vopak and the pending sale of the Simon Group. The year since then has seen little change, certainly as far as Europe is concerned – the financial arrangement under which Vopak divested itself of its chemical distribution activities has left it short of cash in the near term, while the potential sale of the Simon Group as an entity stretched on until early this year when in fact Simon Storage was bought out of the group by private equity investors.

With the Simon situation now clarified – at least as far as tank storage and related activities are concerned – there may be some moves in the offing. It is known, for instance, that the investors are keen to expand the business and this is likely to involve acquisitions in mainland Europe. Moreover, the investors also bought out the Vopak shareholding in the jointly owned terminals, suggesting that Simon Storage may now be able to move more nimbly to take advantage of investment opportunities.

For now, however, and excepting a couple of major new projects, very little is happening in Europe. This reflects the maturity of the market in which terminal operators' customers work as well as, perhaps, the non-discretionary costs heaped on operators by constant additions to the regulations that govern them. At the same time, the indepen-

Odfjell continues to upgrade the Botlek site in Rotterdam

Tanks going in at LBC Antwerp

dent tank storage industry is fast catching up with its customers in terms of its global approach and a lot of investment is currently heading east, not least to the major growth market in China.

While Vopak and Oiltanking, the two largest independents, have long had a very international outlook, others are following suit. Odfjell has been very active in Asia and Latin America in recent years, and recently opened a major new facility in Korea, which it hopes will take advantage of new trade flows into and out of China. Following its foray into the US market, LBC has opened an office in Shanghai and is actively seeking opportunities in the region. And ST Services has over the past year added Australia and New Zealand to its portfolio through the acquisition of Terminals Pty Ltd. All this has had the effect of drawing investment money away from the established markets in Europe and North America.

Where the money is going

There are, however, some exceptions, and Oiltanking is involved in two major projects in the ARA (Amsterdam-Rotterdam-Antwerp) zone, both in very close cooperation with a customer. Both are also primarily chemical terminals, which is an area where the German company has expanded lately compared to its historical concentration on oil terminals.

In Terneuzen, work was due to start in July on the long-awaited 335,000-cm De Mosselbanken facility, which is sited alongside Dow Chemical's plant and will serve mainly as a terminal for the company. Phase one of the project is scheduled to open in early 2005, when 12,000 cm of the 156,000-cm capacity will be available for hire by third parties. It will be able to accommodate ships of up to 100,000 dwt and will feature a mix of tank types and sizes. Oiltanking is using the 'cup tank' design, in which an outer skin serves as secondary containment, so avoiding the need for bund walls and reducing the tank farm's footprint.

Oiltanking's other major project is in Antwerp, where it has embarked on an 11,000-cm gas storage expansion on behalf of its neighbour Oxeno, an affiliate of Degussa. Oiltanking already handles Oxeno's storage requirements in Antwerp but is adding four new bullet tanks to cope with an expansion in butene-1 production. In addition, nearly 75,000-cm of chemical storage capacity is to be added at Antwerp in the next phase, beginning with 15,000 cm next year.

Oiltanking has also recently completed a significant expansion of capacity at its Amsterdam terminal, adding over 150,000 cm in large tanks by the end of 2002, and has another three 25,000-cm tanks due to open for business in October.

Other operators who are investing in the ARA region include Den Hartogh, which is currently adding new stainless steel tanks at its Moerdijk facility. Along with a rail-connected tank container terminal opened in May, the €10mn investment aims to turn Moerdijk into a full-service logistics centre for the chemical industry.

In Rotterdam, Odfjell and Vopak continue to upgrade their terminals at Botlek. LBC's terminal at Antwerp is now full, the latest expansion bringing capacity up to 250,000 cm, and the company has now secured a site across the River Scheldt where a new facility will be built once demand is apparent. ADPO, currently the only terminal on the left bank, is looking at adding 16,000 cm of new stainless steel capacity and is also installing several small mild steel tanks at its Ghent site.

In comparison, there is very little activity in southern Europe. TEPSA is currently building three 18,000-cm tanks at Bilbao and LBC has added some mild steel tankage at its site at Santander. These additions apart, most operators seem intent on improving berthing facilities and rail connectivity to enhance the level of service they can provide to customers.

Of potentially greater interest over the coming few years will be eastern Europe, where the impending entry into the EU of ten countries is encouraging investment in transport infrastructure of all sorts, not least for the oil and chemical industries. US-based operator Westway, part of the ED & F Man sugar-trading combine, has already moved into Poland and opened a 20,000-cm terminal for the import of chemicals and export of molasses and fertilisers. This is to be expanded to 45,000 cm. Nafta Polska is now in negotiations with Vopak that may result in the terminal specialist being involved in the privatisation of Naftobazy, which operates 23 product terminals and a pipeline supply network.

Yet more regulation

Terminal operators have a great deal of discretion in how they invest to upgrade or expand their sites and often only do so when there is firm interest in their facilities. However, in other areas, they have less choice. For instance, many terminals are still having to spend money to bring their facilities up to scratch with regulatory requirements, particu-

Oiltanking Amsterdam, with new tanks going up

larly in the area of vapour control.

Another factor, mentioned in this review last year but still going strong, is the EU's Seveso II Directive (96/82/EC), which has brought many tank storage facilities into scope of a requirement that they avoided in the original Seveso Directive. The main task facing terminals has been to prepare and develop incident response plans and an incident reporting system, which has proven to be rather costly.

Much of the risk analysis work undertaken to meet the requirements of Seveso II will now come in useful for those terminals – mainly those that handle seagoing ships – that will be affected by the International Ship and Port Facility Security (ISPS) Code that was agreed by the International Maritime Organisation (IMO) in December. The Code is the international response to the increased awareness of a security threat from shipping activities and places a similar responsibility on facilities to assess the level of risk from terrorist activity and to take necessary steps to mitigate that risk.

Meanwhile, European terminal operators have another EU directive to worry about – the Integrated Pollution Prevention and Control (IPPC) Directive. Basically, the IPPC Directive calls on industries to establish a set of best available technique reference notes, or BREFs, by which operators and regulators can assess whether a particular facility is doing all it should to minimise its impact on the environment. As far as terminals are concerned, this refers primarily to air emissions. It is noticeable that, in this requirement, there has been a significant shift away from the previously applied concept of 'best available technology not entailing excessive cost', or BATNEEC, although there is a cost/benefit element in the analysis.

Work on the Storage BREF began as long ago as 1999 under the direction of

continued on p43...

The third way

Enhanced oil recovery (EOR) has the ability to add years of life to a well-depleted field or to open up huge reserves of formerly uneconomic petroleum deposits. But even EOR has its limits, as *Gordon Cope* discovers.

Above: Nexen's Long Lake SAGD project
Photo courtesy of Nexen (www.nexeninc.com)

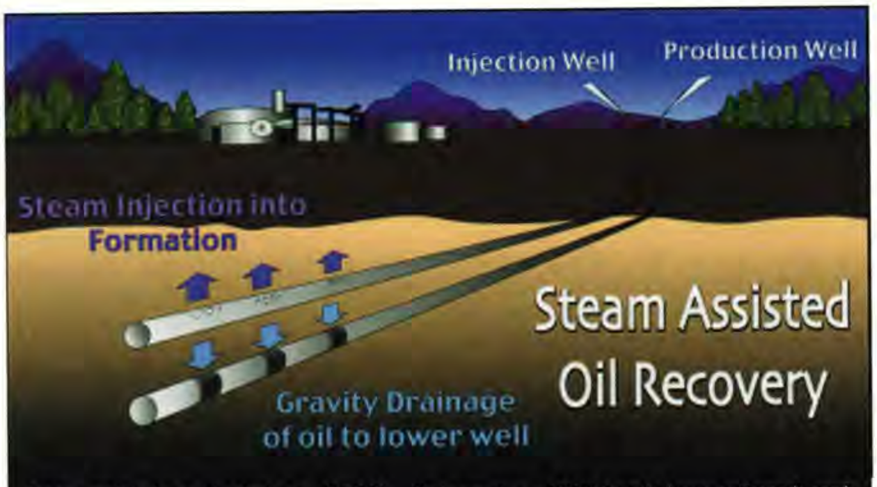
Western oil-producing countries are facing a serious dilemma – not only are new discoveries becoming smaller and less frequent, but output has gone into steady decline. In the UK sector of the North Sea, for instance, production has already dropped 19% since its peak in 1999. In Western Canada, conventional light crude has dropped 10% since 2000. And in the US, production has been creeping down at a rate of approximately 3% annually since the early 1970s.

All is not lost, however. According to a recent industry survey, enhanced oil recovery (EOR) adds an estimated 700,000 b/d to US production. The US Department of Energy (DOE) is conducting a \$138mn programme to extend EOR techniques across a broad range of oil and gas fields. It estimates that EOR has the potential to add up to 1mn b/d and 19bn cf/d to domestic production by 2015. And in Canada, the Canadian Association of Petroleum Producers (CAPP) predicts that bitumen recovered using EOR will increase from 300,000 b/d in 2002 to 385,000 b/d by the end of 2003.

Essentially, EOR uses a wide range of techniques to recover the oil and gas left behind by conventional production means. When first tapped, petroleum reservoirs often contain enough formation pressure to push oil into the wellbore, where it can be lifted to the surface by pumps. This is called primary recovery and can amount to approximately one-third of oil-in-place.

The life of an oil field can be extended through secondary recovery, which often takes the form of a water flood, in which water is injected laterally to push oil toward a production well. Typically, secondary techniques can double recovery rates. 'Recovery factors are quite high in North Sea fields, around 60%,' says Jeremy Thompson, head of Reserves Evaluation at PGS Research Consultants, based in Maidenhead. 'Most fields are designed with water floods from the word go.'

Some fields, such as those with heavy oil or complex fracture patterns, do not respond well to secondary techniques and it is then that tertiary, or EOR techniques, are employed. In addition to thermal and miscible gas injection, surfactants and polymers – and even seismic vibration – are used to shake oil free of its earthly bonds.



Steam-assisted gravity drainage (SAGD) Photo courtesy of OPTI Canada (www.opticanada.com)

Thermal and miscible gas injection

Many reservoirs contain oil that is too heavy to flow to the wellbore unless the viscosity is decreased through the addition of heat. Steam-cycling involves the injection of steam into a well where it transfers heat energy as it condenses. The well is then put back in production and the heated oil lifted to the surface. This method is quite common in California, where production of heavy oil exceeded 370,000 b/d in 2002.

In addition to steam-cycling, Canadian producers have had success with SAGD, or steam-assisted gravity drainage. This involves the drilling of two horizontal wells through the reservoir, one immediately on top of the other. Steam is injected into the top well, and the heated oil flows down into the lower production well (see **Figure 1**).

Encana's Foster Creek project, currently producing 20,000 b/d, has plans to expand the facility to 30,000 b/d by 2004, and the company has begun production at Christina Lake, a bitumen reservoir with sufficient reserves to produce 70,000 b/d for 30 years. Suncor Energy has also started construction on the Firebag project, slated for initial production of 35,000 b/d bitumen in 2004, rising to 140,000 by 2010.

Miscible gas injection involves the introduction of natural gas or carbon dioxide (CO_2) under high pressure into a reservoir. The gas dissolves in the crude, reducing viscosity and allowing the oil to flow to the wellbore. The process works best in carbonate rock reservoirs that lack natural water drive, gas caps and major fracture patterns. Projects last 10–30 years and enhance oil recovery by 7–15% of original oil-in-place. Generally, gas injection is economical if oil is above $18/b and the injection gas costs less than $1 per 1,000 cf. Most of the successful projects of this type depend on tapping and transporting (by pipeline) CO_2 from underground reservoirs. Texas, where several natural CO_2 deposits occur (such as McElmo Dome and Sheep Mountain), produced over 210,000 b/d in 2002 using this method.

Problems

The rising cost of natural gas and electricity negatively impacts EOR production of both heavy oil and bitumen. Natural gas is the most common energy source to heat steam and some form of electrical pump is normally needed to lift the oil to the surface. Industry experts estimate that each barrel of oil produced under these circumstances requires approximately 0.8mn Btu of natural gas and 20 kW of electricity. In January 2001, when natural gas and electricity costs spiked in both California and Alberta, the direct lifting costs per barrel of oil produced rose from approximately $4 to $8. Since then, electricity and gas prices have moderated, but this spring natural gas contracts shot up in the face of cold weather and storage draw-downs, and the long-term prospect for the price of natural gas in North America is to remain high as production shrinks and demand increases.

One way to reduce energy costs is to replace the steam with solvents in a manner similar to a water flood. Demand for solvents is currently high, however (it is used to transport bitumen in pipelines), and it can become an uneconomic alternative if too much of the solvent is lost through inadequate injection control. A more promising solution is to replace natural gas with a less expensive fuel source. Nexen and OPTI Canada have begun construction on the Long Lake SAGD project (see **main photo**), which is expected to produce 70,000 b/d by 2007. They plan to heat the steam using synthetic oil created from the bitumen by an on-site upgrader.

In the US, relatively little natural gas is used in miscible projects, the majority using less-expensive CO_2. Many reservoirs, however, are not amenable to its use. When mixed with water CO_2 produces a corrosive liquid. Fields that are 'sour' (they have a high CO_2 or hydrogen sulphide content) are fitted out with stainless steel production lines to withstand the corrosion, but those that are 'sweet' are usually equipped with less expensive standard steel. Any CO_2 leaking out of a sweet reservoir would cause extensive damage to its production facilities. This problem has bearing not only in North America, but in the North Sea, as well.

North Sea heads south

To date, production in the mature North Sea sector has amounted to approximately 34bn boe. Known recoverable reserves are estimated at up to 78bn boe so, at first glance, the basin might be a prime target for EOR. Surprisingly, however, there is little in the way of tertiary recovery under way. 'BP uses miscible gas injection at the Magnus field,' notes Thompson. 'The project gives a 3% increase in recovery, which is very significant in a field like Magnus.' Magnus is the exception, rather than the rule, however. 'The gas is from a BP field west of the Shetlands, where the infrastructure to get it to market is too expensive. It was the best available solution to a problem of stranded gas. It made a good economic fit because all the factors came together.'

In January BP announced the sale of the Forties field to Apache, heralding a trend for super-majors to divest larger, mature fields. Thompson doubts that new owners will resort to tertiary techniques, however. 'The new operators are smaller and more nimble, and they can do a number of other things to extend field life, like optimising the use of production technology and artificial lift, doing reworks, etc.' The trend for new fields in the North Sea to be much smaller than their predecessors also works against EOR. 'For fields under 100mn barrels, the size doesn't justify the R&D,' comments Thompson.

Finally, he notes that one has to be very careful reworking wells in North Sea fields. 'It's not like North America where you have 4,000 wells in a field – if you lose one or two, it doesn't matter. In the North Sea, a well costs $10mn to drill and $2mn to complete. You have to be careful what you do to them. Fraccing [injecting sand under high pressure into a reservoir through the well bore in order to increase field permeability] can increase production, but it can also destroy a well.'

The use of chemicals is another method that can recover missed oil. Surfactant, a detergent material, creates a very low surface tension between the reservoir rock and oil, thus allowing the rock to be 'scrubbed' clean. Often the water flood behind the surfactant is made viscous by the addition of a polymer in order to prevent the water from breaking through and then bypassing the surfactant. Surfactant flooding generally works well in non-carbonate rock, but the surfactant material is expensive and large quantities are required. 'They experimented in the 1980s in the North Sea with surfactants and polymers,' says Thompson. 'In general, conditions in regard to formation water and temperatures were beyond what polymers and surfactants could cope with. Most North Sea fields are very warm and the formation waters are quite saline. Polymers and surfactants prefer low temperature, low salinity conditions.' In the US there are only a handful of chemical injection projects under way, primarily on an experimental basis.

Sequestration

A relatively recent development has added a new wrinkle to the EOR game. The Bush administration has entered into a consortium with several state governments to investigate the 'sequestration', or permanent removal, of CO_2 from the ecosystem in order to deal with environmental safeguards.

According to the US Environmental Protection Agency (EPA), human-made (anthropogenic) CO_2 emissions amount to 6bn t/y. It is estimated that 25mn t/y is injected in the US, resulting in almost 200,000 b/d of oil production. Most of the CO_2 currently comes from natural deposits, but much of that could be sourced from man-made facilities. A study by the US Department of Energy (DOE) shows that CO_2 is routinely separated and captured during ammonia production, hydrogen production and limestone calcinations. Encana, which operates the Weyburn field in Saskatchewan, already uses man-made CO_2 piped from a synfuel plant in North Dakota for its CO_2 flood. The company estimates that it will sequester about 20mn tonnes over the life of the project, while producing an additional 130mn barrels of additional oil.

In order to displace the naturally-produced CO_2 used in miscible injection with man-made gases on a large scale, however, the separation of flue gases (say, from electrical generation plants) would require advances in membrane and cryogenic techniques to make the process economically feasible. Tax credits and carbon emission credits would also be necessary to advance the percentage of CO_2 captured. 'A government could introduce market-distorting regulations to achieve a political goal, such as safeguarding the environment, but operators would need handouts to do it,' says Thompson.

Even then sequestration wouldn't be viable in many oil environments. 'Most North Sea fields are sweet, with very little CO_2 or hydrogen sulphide, so they were completed with standard steel instead of stainless or chrome steel,' says Thompson. 'If you inject CO_2 into a North Sea oil field you have the potential problem of the fluid breaking out and rotting the production tubing.'

On the other hand, if the goal is to simply get rid of CO_2, then depleted gas fields make ideal hosts. 'Many of these fields had several tn cf of reserves, so there's plenty of room.'

The future

Thanks to the high price of oil and declining production rates, new ways of increasing field recovery are evolving. For decades operators in the seismically-active state of California have noted that field production can temporarily rise after a nearby earthquake. Applied Seismic Research of Plano, Texas, has developed a downhole tool that produces high energy, low frequency vibrations similar to an earthquake. Its research has shown that the best reservoirs for seismic stimulation include those with a simple structure, medium-density oil and low gas content. A month-long test in conjunction with the Los Alomos National Laboratory at the Lost Hills field in California showed a production increase of 26%. Producers still see this method as experimental, however, and it is not in wide use.

In conclusion, although EOR can show significant gains in oil recovery, it is not considered the answer to the world's increasing need for oil, nor the West's increasing reliance on Opec imports. EOR requires extensive R&D in order for each field to maximise recovery and minimise damage, as well as the confluence of a number of different cost and benefit factors in order to be applicable across the sector. While advances in traditional techniques (and the introduction of new black boxes) may add a few percentage points onto the recovery for a while, no technological magic can defy the logic of the marketplace. As Thompson points out: 'In the end, it has to be economically viable to work'.

IN NEXT MONTH'S ISSUE

The September 2003 issue of *Petroleum Review* will feature our annual North Sea survey, rounding up the latest developments in this sector and reviewing future prospects. Consultant Wood Mackenzie appraises new entrants in the North Sea 'Top-50' oil companies, while John Brooks CBE, formerly Director of the UK DTI's Consents and Exploration department, presents a personal view of the current status of exploration on the UKCS and measures required to stimulate further activity. The feature will also include a closer look at the stacked multilateral drilling system used to improve reservoir drainage on the Troll Olje field and how subsidence of the base structure on Vigdis B has been halted.

Analyst Douglas-Westwood will be providing analysis of the worldwide subsea and floating production markets, while IHS Energy will present the results of its latest *World Petroleum Trends* report.

The September issue will also be taking a closer look at a collaborative industry study to optimise gas compressor performance, and a prominent analyst will review US energy security in the 21st century.

Algeria – a reserves hot spot

Algeria is a country that many in the oil and gas industry view as a politically difficult and challenging region to operate in. Although commercially attractive contracts have been available since 1986, the impact of fundamentalist activities has had a limiting effect on major inward investments. Despite this, at least 30 international oil and gas companies are now active in its as yet under-explored and immature hydrocarbon provinces that cover roughly two-thirds of the country, write *Malcolm Brierley*, Technical Director, and *Geoff Eyre*, Managing Director, Bayphase.

The resulting exploration success in Algeria is now feeding through to a year-on-year increase in liquids production from 1.4mn b/d in 1997 to 1.9mn b/d in 2002, with a projected target of over 2.5mn b/d by 2004. Gas production has similarly increased from 5bn cf/d in 1982 to nearly 14bn cf/d in 2002. Gas projects under development such as In Salah, Ahnet, Ohanet, In Amenas, Gassi Touil and the recently discovered Menzal Ledjmet East will have an immense impact on the commercial viability of gas production in the region.

Significant opportunities

What this means in terms of future potential for Algeria is that significant opportunities for existing and new international investors will be generated through a rapid increase in major investments via the current 4th Licensing Round being held this year, along with major midstream and downstream contracts required for the upgrading of export, refining and communications infrastructure.

Bayphase's review of the oil and gas upstream, midstream and downstream sectors* has identified the scale and nature of the opportunities available, and the level of investments required over the next 10 years. Based on our assessment of available data there appears to be up to 43bn barrels and 282tn cf of ultimately-recoverable oil and gas reserves potential in Algeria. Up to the end of 2002 the country had produced 14.3bn barrels of oil and 83tn cf of gas – leaving a remaining reserves *potential* of 28.8bn barrels of oil and 199tn cf of gas.

In terms of oil this represents an amount equivalent to around 1.5 times the historical production from the UK North Sea that could remain available for exploitation, generating the associated investment requirement. In terms of gas reserves this represents an amount equivalent to around three times the historical production from the UK North Sea.

Reserves assessment

Overall, the status of Algeria's upstream oil industry is probably best expressed in terms of its reserves. We have classified these in to seven basic categories (see **Table 1**).

The assessment has been based on published information and data gathered whilst executing studies for a number of clients. In terms of future exploration potential, we believe that Algeria has a significant number of world-class exploration opportunities available in each of its three primary hydrocarbon provinces, and that new exploration provinces are now being opened up in the north of the country, along with offshore acreage.

Investment assessment

We have also implemented a detailed assessment of the whole of Algeria's oil and gas sector to determine the range of investment required should the country's plans for its upstream, midstream and downstream sectors come to fruition – see **Table 2**. In addition, we have considered the investment requirements of Algeria's oil and gas industry related infrastructure.

** Full details on all elements of Algeria's oil and gas industry, Bayphase's reserves assessment and its investment analysis can be found in its recently published report. Visit* **www.bayphase.com** *for more information.*

Field area	Number of fields/ prospects	Recoverable oil reserves (bn barrels)	Recoverable gas reserves (tn cf)
Triassic/Ghadames Province **Producing fields**	23	18.8	122.2
Illizi Province **Producing fields**	11	2.8	12.7
Grand Erg/ Ahnet Province **Producing fields**	1	–	1.1
Triassic/Ghadames Province **Non-producing fields**	9	2.9	10.4
Illizi Province **Non-producing fields**	6	0.9	10.5
Grand Erg/ Ahnet Province **Non-producing fields**	11+	0.1	16.3
Exploration and enhanced recovery potential	Over 200	17.7	108.4
Total	**260+**	**43.2**	**281.6**

Table 1: Algeria's ultimately recoverable oil and gas reserves

Sector	Total capital investment projected ($mn)
Upstream – oil and gas fields	19,718–27,853
Midstream – pipelines and terminals	9,945–3,905
Downstream – refineries, petrochemicals and gas processing	4,665–6,190
Subtotal	*34,328–47,948*
Oil related infrastructure – transportation and power	15,830–25,170
Total	**50,158–73,118**

Table 2: Summary of capital investment requirements of Algeria's oil and gas industry and associated infrastructure

Canada oil patch update

Thanks to strong commodity prices the Canadian oil patch is expecting another excellent year, but the extended boom is overheating some parts of the sector. *Gordon Cope* looks at the highs and woes.

Above: Petro-Canada has a 12% interest in the Syncrude operation near Fort McMurray, Alberta

After a slight downturn of activity in 2002 the Canadian petroleum industry is on its way to a stellar year. According to ARC Financial Corporation, a Calgary-based consultancy, overall gross production revenues are expected to jump to C$70.8bn, up from C$60bn in 2002.

The key, of course, is the sustained price of oil and gas. Thanks to the uncertainty of supply due to war in Iraq and the disruptions in Venezuela and Nigeria, 1Q2003 prices for West Texas Intermediate averaged $32.44/b, while natural gas (Henry Hub) held above $6/mn Btu.

But too much success can create its own excess. The last three 'boom' years (gross production revenues have almost doubled since 1999) have created tremendous pressure to reinvest in the sector. Good investment opportunities at home are becoming relatively scarce and some projects are being rushed ahead of engineering planning. The demand on relatively scarce labour and manufacturing resources is driving up costs on everything from well completions to oil sand plants.

The Canadian oil patch also faces profound structural changes. The merger mania of 2001, which gutted the ranks of intermediate and senior independent producers, was a significant factor in the 20% fall in well count in 2002. In the future, decisions to spud a Canadian well by US parents will be made against other competing basins in the North American continent.

All that said, it's still difficult to shed a tear for a sector with an estimated C$30.6bn in after tax cash flow. Here is where the major money will go.

Conventional oil

The total number of oil wells this year is expected to reach the 4,500 range, up from 4,000 in 2002, as oil companies spend approximately $11bn on drilling. Most of the wells will be spudded in the Western Canada Sedimentary Basin, a large swathe of petroleum-prone rock stretching from British Columbia, through Alberta and Saskatchewan, to Manitoba (estimated to still hold over 4.5bn barrels of recoverable oil). With over 400,000 wells drilled in the last half century, however, the basin has entered into a mature phase where each new well chases after smaller and smaller targets. This factor, tied in with the petering-out of fields discovered in the 1940s and 1950s, is mirrored in the basin's drop in conventional oil production from 735,000 b/d in 2000 to approximately 664,000 b/d for 2003, a long-term decline of approximately 3%/y.

This decline is being sharply offset by growth of production on the East Coast, with proven reserves of oil in the Jeanne D'Arc Basin now exceeding 1.5bn barrels. The Hibernia field is expected to boost output this year by 40,000 b/d, to 220,000 b/d. The nearby Terra Nova field, which began production in 2002, will lift its production by 55,000 b/d, to 160,000 b/d. The White Rose field, currently under construction, is expected to enter production late in 2005.

Outside of Jeanne D'Arc, however, new finds are proving elusive. In June Petro-Canada announced it was abandoning an exploratory well drilled in the Flemish Pass Basin, 445 km east of St John's. The Calgary-based company also abandoned another exploration well in the region in April. The cost of the two dry wells exceeded C$50mn.

Petro-Canada's Mackay River site – four steam generators, a key component of producing bitumen using horizontal well pairs

Natural gas

Of the 17,000 wells to be drilled in Canada this year, almost two-thirds, or 10,700, are expected to be gas wells. Even this torrid pace will only result in the industry standing still. According to the Canadian Association of Petroleum Producers (CAPP), national production of 17.53bn cf/d in 2002 is expected to decrease to 17.26bn cf, an average drop of 270mn cf/d.

Other reports are even more drastic. FirstEnergy Capital of Calgary issued a statement in June that 2003 drilling performance in the Canadian gas sector had been disappointing and that the sector could see a drop in production by as much as 500mn cf/d. In addition, the Alberta Energy Utilities Board (AEUB) is adjudicating on a dispute in the Surmont area of north-eastern Alberta. Owners of 100bn barrels of bitumen in the region are concerned that the removal of natural gas from nearby channel sands might reduce reservoir pressure below the level needed to conduct steam-assisted gravity drainage (SAGD). If the AEUB does eventually close the wells, the decision will remove another 225mn cf/d from production.

The decline, while seemingly minor compared to the 60bn cf consumed daily in the US, has profound implications in the long term. The EIA predicts that US gas demand could grow to 96bn cf by 2025. When faced with a recent 2.8% drop in the US gas production rate, however, the supply/demand crunch is already being felt in the marketplace. Current US gas prices remain very high for the summer, in the $5.50–$6/mn Btu range, and despite some weeks of record injection, gas in storage at the end of June remained at 17% below the five-year average level.

Even US Federal Treasury Chairman Alan Greenspan was sufficiently concerned to tell Congress in June that the shortfall could cause 'some erosion' in the US economy.

One recent bright spot has been production in eastern Canada off the coast of Nova Scotia, an under-explored area close to large markets in the northeast US. The Sable gas field, which entered production in 1999, is now producing 0.5bn cf/d from 2.6tn cf of reserves. The Toronto-based ExxonMobil subsidiary, Imperial Oil, has plans to spud a well this summer on a promising structure located in the same geological province. The NEB estimates the area holds 15tn cf of gas. A recent industry survey by CAPP reveals that C$1.5bn will be spent on the east coast this year, up from C$1bn in 2002

Some petroleum companies have lately been signalling a more cautious attitude toward the region, however. In 2002 EnCana announced plans to spend C$1.1bn to exploit the 1tn cf of reserves in its Deep Panuke field, located 250 km east of Halifax. A pipeline would carry 0.4bn cf/d from a platform above the field, starting in 2006. In February, however, Encana applied for a 'time-out' in the approval process in order to incorporate new information regarding market conditions and exploration information. At a recent conference in Calgary, Shell Canada Vice President Dave Collyer noted that the drilling off Nova Scotia has shown that the geology is more complex than originally expected and oil companies are less optimistic about the area than they were half a decade ago. More promising results will be needed to sustain the current level of investment in the future.

Arctic pipeline

Hopes for relief in the tight natural gas market over the next decade now focus on the Arctic. There are two competing proposals to bring Arctic gas south – the Mackenzie Valley pipeline and the Alaska Highway pipeline. The former proposes to connect 5.8tn cf of proven reserves in the Mackenzie Delta to the existing North American gas network through a 1,300-km pipe running south to Alberta, while the latter, a 2,800-km line running from Prudhoe Bay through Alaska and the Yukon, promises to deliver 3.4bn cf/d to markets in Canada and the lower 48 States.

Which project proceeds first, or at all, is subject to a number of factors. The Alaska project has strong support from the State of Alaska, the Bush administration and Congress in Washington. While many fields in the Gulf of Mexico are in permanent decline, Prudhoe Bay holds 34tn cf of gas reserves, enough to easily supply the pipeline for several decades (and probably much longer).

The primary drawback to the project is the cost – an estimated $12bn to punch through the frozen Tundra, then possibly a further $8bn to upgrade the gas network in Alberta to handle the surge in load. It would be the world's largest single petroleum project, tying up immense amounts of capital and resources for several years. To make matters worse, the energy transportation sector in North America is going through a periodic slump, compounded by the meltdown at Enron, a price fixing scandal in California and a suspicious regulatory regime, making the raising of capital a difficult and costly affair.

On the other hand, the Mackenzie Valley pipeline, moving some 1.3bn

Petro-Canada drilling activity in the Wildcat Hill-Benjamin Creek area of Western Canada

Petro-Canada uses an environmentally sensitive drilling rig while exploring for natural gas in the Mackenzie Delta. It is designed to redistribute all waste heat generated by rig operations. The process saves fuel and reduces emissions of NO_x and CO_2 into the atmosphere

cf/d, is expected to cost in the order of \$3bn. In June TransCanada Pipeline (TCPL) and the four main producers – Imperial Oil, Shell Canada, ConocoPhillips and ExxonMobil – reached an agreement in which TCPL would loan the Aboriginal Pipeline Group, which will own one-third of the pipeline, their share of initial development costs, in the order of \$C80mn. This key agreement with the Dene, Inuvialuit and Metis communities will pave the way for a formal review process, starting in 2004. Experts suggest that the Mackenzie Valley will have an initial throughput of gas sometime around 2009, with full production by 2011. By the time the pipeline is completed the gas won't have far to get to market – the oil sand projects in northern Alberta alone are expected to consume 1bn cf/d by 2010.

The Alaska Highway project is expected to take longer. The producers – ExxonMobil, BP and ConocoPhillips – envision a lengthy negotiating process to resolve royalty and tax guarantees, permitting legislation and binding dispute arbitration before any pipe hits the permafrost. If all goes well, the first shipments of gas may reach the lower 48 States sometime in the middle of the next decade.

Oil sands

Last year, 2002, was a brilliant year for oil sands and heavy oil. The production of synthetic crude reached 440,000 b/d, heavy oil from oil sands (that has been recovered through augmented methods such as steam-assisted gravity drainage, or SAGD), stood at 300,000 b/d, and conventional heavy oil production surpassed 553,000 b/d. These three categories accounted for 67% of total Canadian crude output.

CAPP predicts that 2003 will be equally positive. Thanks mainly to the completion of Shell's Athabasca oil sands project, synthetic crude production is expected to rise to 566,000b/d. In-situ production of bitumen will grow to 385,000 b/d, with conventional heavy oil decreasing slightly to 546,000 b/d. Further investments in the range of \$5bn over the next several years are expected to keep long-term growth in oil sands at a healthy clip, with production possibly reaching 2.3mn b/d by 2015.

That said, all is not well in the sector. Alarm bells are sounding as budgets spiral toward the Northern Lights. Shell's Athabasca oil sands project, originally slated at C\$3.5bn, ended up exceeding C\$5.2bn. Suncor and Syncrude also saw several billion dollars added onto their projects. Various factors for the cost overruns have been cited, including a shortage of skilled labour, hasty engineering and delays in delivery of key materials, but the overall effect on long-term plans is chilling. During its AGM in April Petro-Canada announced it was putting the brakes on approximately C\$5.8bn in oil sands projects, including the development of the 85,000 b/d Meadow Creek mine and the re-engineering of its Strathcona refinery near Edmonton to take bitumen feedstock. Canadian Natural Resources also announced that an C\$8bn investment in its proposed 300,000 b/d Horizon project is also under review.

Cost overruns aren't the only factors stoking the bitumen blues – in December the Canadian Government officially ratified the Kyoto Protocol, which sets targets for greenhouse gas (GHG) emissions at 6% below 1990 levels. CAPP estimates Canada's annual CO_2e emissions could be in the range of 810 megatonnes per year, well above the Kyoto target of 570 megatonnes. Meeting the target through carbon credits could add 30 cents to each barrel of synthetic crude, an unwelcome addition to rising production costs. The use of SAGD – in which a pair of horizontal wells are drilled, then steam injected into the upper well to heat the bitumen sufficiently to allow it to drain into the lower well – is being hit by rising costs of natural gas, adding between \$4 and \$8 to the cost of lifting the gooey stuff.

In spite of the troubles oil sands and heavy oil remain low risk ventures, and producers are looking at ways to reduce cost overruns, displace natural gas consumption and lower carbon emissions. In May, ConocoPhillips and partner Total were pleased to receive regulatory approval for their C\$1bn Surmont project. The plan is to begin production on a SAGD facility that will lift 25,000 b/d by 2006, with an eventual expansion to 100,000 b/d. They, along with other major players in Canada, know that the insatiable appetite for oil and natural gas in the US market will continue to ensure a healthy petroleum sector in their country over the long term.

All photos courtesy of Petro-Canada

Setting the standard

Jim Crighton and *Harry Read* of Global Fuels Technology, BP Oil International, together with *Mike Sargent* of LGC, look at the development of standard test methods and reference standards for determining low levels of sulphur in road transport fuels.

In 1997 it was recognised that the existing standard test methods for determining sulphur in transport fuels were not suitable for the low levels that would be required to meet the proposed 2000 and 2005 specifications. In order to address this problem within Europe the CEN Technical Committee 19 set up Working Group 27, which would be 'concerned with the comparison of sulphur content determination methods for sulphur levels not greater than 0.1 % m/m'.

Round robins

Working Group 27 organised two large European round robin exercises. The first in 1998/1999 involved 69 laboratories from nine countries, testing eight petrol and seven diesel fuel samples with sulphur contents in the range 5 mg/kg to 500 mg/kg by the existing European Norms and some new standard test methods. The second in 2000, involving 92 laboratories from 10 countries, looked at samples with sulphur contents of 1 mg/kg to 60 mg/kg.

The new test methods being developed, the results of the round robins and the requirement for low sulphur content Certified Reference Materials (CRMs) were the subject of a series of Sulphur Workshops organised by the Institute of Petroleum (now the Energy Institute).

Improving precision

The results from the first round robin exercise showed disappointing precision for most of the test methods at concentrations below 50 mg/kg level, with many of the methods failing to meet the requirements for testing at the lower specification limits. In order to try to improve the precision of the test methods it was decided to repeat the exercise using independent reference values based on a definitive measurement technique. It was also agreed that low sulphur content CRMs were needed to verify the correct functioning of the apparatus, operational procedures and 'bias' between test methods.

The UK LGC (Laboratory of the Government Chemist), in collaboration with BP Oil International, agreed to provide the reference values and to develop CRMs using a novel technique. This involves Isotope Dilution-Mass Spectrometry (IDMS) using microwave digestion of samples followed by Inductively Coupled Plasma Mass Spectrometry for the isotope ratio measurement.

Reliable comparison

The IDMS data was used in the second round robin, facilitating a reliable comparison of the performance of several industry standard methods, including those developed by the working group. The precision values obtained for the test methods were greatly improved compared with those of the first round robin.

Following the second round robin six diesel fuels, representing the range of sulphur contents currently required and the lowest legislative limits that may be expected in Europe within the next 10 years, have been provided by BP Oil International to LGC for certification as reference materials. Experimental work for the certification of a 50 mg/kg CRM has been completed and certification of the other materials is expected to follow shortly, with priority being given to the 30 mg/kg and 10 mg/kg levels.

A detailed description of this work has been published in the VAM *Bulletin* (Spring 2003), copies of which may be obtained from the LGC or downloaded from the VAM website at **www.vam.org.uk** LGC reference materials are distributed by LGC-Promochem (**www.lgcpromochem.co.uk**).

Politics dominate US energy scene

Although elections won't be held until November 2004, the Bush administration's quest for re-election has coloured its energy initiatives, writes *Judith Gurney*. This is particularly evident with regard to restrictions on exploration in areas known to contain ample, undeveloped oil and gas reserves, such as in federally controlled waters off the coasts of the key electoral states of Florida and California.

Early this year the administration announced that it would buy out existing oil and gas leases in waters off the Florida Gulf Coast, estimated by the Minerals Management Service (MMS) to hold 2bn barrels of oil and 8tn cf of gas. At issue here are nine of the 11 leases in the Destin Dome project of ChevronTexaco and ConocoPhillips; a project that is now dead. As the federal government and the littoral state governments have veto power over the development of the two other Destin Dome leases and can therefore prevent their exploitation, the buyout effectively kills this offshore natural gas project. In addition, the administration has announced that it will not contest the right of the state of California to prevent development in existing leases in federal waters off its coast. At issue here are 36 leases that the MMS estimates to hold more than 1bn barrels of oil and 500bn cf of gas.

Supply situation still critical

It is not as if the crude oil supply situation in the US is improving, as dependence on imports to meet domestic demand is continuing unabated. The Energy Information Agency (EIA) reports that, on average, more than 60% of total oil demand in the US was met by imports in 2002 and estimates that imports may supply 65–70% of demand by 2025. The current supply situation is worse than usual, having been affected by the Venezuelan oil strike, Nigerian unrest and the war in Iraq. Crude stocks at the beginning of the summer were at their lowest level in decades. Oil prices, which were expected to fall dramatically at the end of the Iraq war, have so far failed to do so, with early summer benchmark prices around $30/b.

Sources of imported oil do not vary much from year to year, with Opec continuing to provide about half of all imported crudes. Presumably, once Iraq oil fields come back onstream with sizeable outputs the US will import more oil from this source. Russia is another supplier whose share may increase as Russian oil companies are said to be planning a $1.5bn export oil facility at Murmansk that could be operational by 2005. Although a deepwater port situated at Murmansk could handle supertankers for oil shipment to the US, some analysts are skeptical of the profits of such a trade and question estimates that Russia would strive to meet 10% of US import demand, up from the current level of less than 1%.

Progress on new domestic sources

On the other hand, some of the Bush administration's energy initiatives that do not require Congressional approval are proceeding, albeit slowly. There are moves to relax regulations restricting road-building and, therefore, oil and gas exploration and production, in areas of the Rocky Mountains where a government study has estimated undiscovered reserves totalling 11.3tn cf of gas and 550mn barrels of oil. These efforts, however, are expected to be opposed by lawsuits brought by powerful environmental groups.

There are also moves to encourage exploitation of oil reserves in the National Petroleum Reserve of Alaska that consists of 22.5mn acres west of Prudhoe Bay, south of the Beaufort Sea. In 1997 the Bureau of Land Management estimated that the eastern section of NPR-A could hold about 3bn barrels of recoverable oil, although in areas difficult and costly for extract and transport. Set aside as an oil and gas reserve by President Warren G Harding in 1923, NPR-A is not protected by the same environmental standards as the Arctic National Wildlife Reserve (ANWR) and the Department of the Interior, on its own, can decide on how to dispose of it. About 20% of NPR-A has been recently leased to major oil companies, with ConocoPhillips and Anadarko announcing discoveries early in 2001.

Energy bill

In the meantime, Congress seems likely to pass an energy policy bill this summer. The House and Senate versions of this bill differ and the terms of a final compromise bill, if it is hammered out, are still uncertain. It will probably include wholesale electricity market restructuring, some streamlining of permits for projects on public lands, and updated clean fuel rules including a mandate for the use of ethanol as an additive for reformulated gasolines. Ethanol is another highly politically charged issue. The Midwest farm states carry a lot of valuable votes in elections. Existing subsidies for Midwest producers of ethanol may be increased in a compromise energy bill.

A final bill is expected to include fiscal support for the proposed \$20bn pipeline to bring Alaskan North Slope gas to the Lower 48 states. There are 35tn cf of proven gas reserves in Prudhoe Bay and the government has estimated as much as 100tn cf of potential gas reserves in the North Slope. Citing potential environmental damage, Congress has banned the construction of a northern gas pipeline under the Arctic Ocean to the Canadian MacKenzie Valley where it would facilitate transport of Canadian Arctic gas to the US. This ban effectively mandates the proposed southern pipeline following the Alaska Highway into Alberta, a route for which the Alaska Natural Gas Transportation System received permits in 1977. That scheme failed due to concerns about market demand.

The compromise bill is likely to include a loan guarantee programme and some sort of production incentives for an Alaskan gas pipeline, but probably not the guaranteed floor price included in the aborted energy policy bill of 2002. The North Slope oil producers – BP, ExxonMobil and ConocoPhillips – have indicated that they are not disposed to go ahead with the pipeline project unless Congress provides generous financial support.

Natural gas

While the administration and Congress move cautiously with an eye to the coming elections, alarm regarding US natural gas supplies and price has been voiced in a number of circles. Gas prices began to climb in late summer 2002 after having remained around \$3/mn Btu for about a year. They then continued relentlessly upward to surpass \$6/mn Btu by this June, but eased back to just over \$5/mn Btu by the end of the month. Statistics reveal current storage levels well below average, inadequate for the coming winter demand. High oil prices exacerbated the upward trend of gas prices, as they provided little incentive for those customers in the industrial and electricity generating sections that have the capacity for fuel switching to purchase oil rather than gas.

In June, Alan Greenspan, US Federal Reserve Chairman, noted a 'very serious problem' regarding tight supplies of North American gas. He warned that high gas prices could be expected to endure for some time and that these could become an increasing drag on the US economy. His remarks came on the heels of a warning by Energy Secretary Spencer Abraham that little potential exists to raise domestic natural gas output. Most gas production in the areas open to exploration is in advanced stages of depletion, with only marginal prospects available. Discoveries from wells in mature fields tend to have impressive initial flows but sharp drops in volume within a year. This kind of output is inadequate to meet a demand for natural gas that is increasing rapidly, largely as a result of new gas-fired electricity generating plants.

Abundant undiscovered gas reserves are believed to exist offshore California and Florida but, as noted earlier, exploration is currently forbidden in these waters. The Senate has an amendment to its energy bill requiring the Interior Department to conduct a survey of potential offshore energy reserves in areas where drilling is now barred, but it isn't clear whether this amendment will be included in a final energy bill.

Undiscovered gas reserves – the MMS estimates between 5tn and 20tn cf, with a most likely level of 10.5tn cf – are believed to exist at considerable depths in wide areas of the shallow waters of the Gulf of Mexico. The MMS hopes to encourage exploration for these deep reserves by offering royalty relief on gas production from depths on new leases, and proposes to extend this relief to existing leases. Despite the high costs and risks associated with depth-drilling and high field pressures, several large independent companies have expressed interest in exploration and BP, ChevronTexaco and Shell have come back to the shelf for targeted projects.

In the long term, if the pipeline gets built, Alaskan North Slope gas will substantially ease the supply shortage. But, even under the best of conditions the pipeline cannot be expected to come onstream until 2012–2014. In the meantime the US cannot count on increased gas imports from Canada until Canadian Arctic frontier gas fields are developed.

Surprisingly, Alan Greenspan came out in support of increased LNG imports and criticised the current regulatory roadblocks for the construction of LNG import terminals. Despite the need for long-term, fixed-price gas contracts to help underwrite expensive upfront investment in LNG terminals, tankers and other infrastructure, a number of companies see the US as a potentially strong LNG market. Shell, for instance, recently announced plans to expand its gas operations to include investment in infrastructure to import LNG into the US. ChevronTexaco has applied for a licence to construct and operate a deepwater port off Louisiana where it will site a LNG terminal, hopefully by 2006. El Paso Global has applied to construct an offshore floating mooring buoy for LNG carriers in Gulf of Mexico shallow waters and there are other projects afoot in Mexico, partly to serve the California market, and one in the Bahamas to serve the Florida market.

Gulf of Mexico

In contrast, the Gulf of Mexico is remarkably quiet, a sort of business-as-usual scene with just two announcements of dramatic discoveries since 1999. Interest is still shown in MMS offshore block auctions, mainly for blocks in ultra-deepwater areas and in shallow-water areas believed to hold deep gas fields.

The MMS reported that there was 'significant' deepwater Gulf of Mexico activity in 2002, which presumably refers to Shell's Great White discovery, despite a general downturn in drilling activity. Great White is reported to be a 500–600mn boe discovery and is the only large discovery since BP's 500mn boe Thunder Horse North discovery in 2000. The MMS also cited 12 discoveries that year, including three in water depths greater than 2,400 metres by Kerr-McGee, BHP Billiton and Shell, and reported that 14 deepwater projects came onstream in 2002. The latter included three projects by BP, three by Kerr-McGee, and other projects by Agip, ExxonMobil, Marathon, Total, Spinnaker and Samedan.

According to MMS estimates, some 18–19 projects will come into production by the end of 2003, and another 15 in 2004. This year's projected starts include five fields in Shell's Nakika project, BP's Mad Dog field and others by Shell, BP, ConocoPhillips, Kerr-McGee, Pioneer and Murphy. A large proportion of Gulf deepwater fields are being developed with subsea systems – almost two-thirds of those in production at year-end 2002/beginning of 2003 were subsea developments – not surprisingly, given the number of fixed platforms, pipeline systems and other hub facilities already existing in the Gulf.

Occasionally truss spars, tension leg platforms and moored semisubmersibles are being installed.

More to come from GoM deeps

The following tabulation covers the Gulf of Mexico (GoM) deepwater fields that have come onstream in 2002 and all those planned or with firm development plans.

According to the July issue of the IEA's *Oil Market Report* Federal Gulf of Mexico production should reach 1.746mn b/d of liquids in 2003 and 1.916mn b/d in 2004. The principal field start-ups contributing to the 135,000 b/d increase in 2003 are the Shell developed, BP-operated Nakika complex of fields, Murphy Oil's Medusa, Total's Matterhorn and Horn Mountain in Mississippi Canyon, and Shell's Habanero in Garden Banks.

In 2004, the 180,000 b/d production increase will largely come from start-ups of Dominion's Devil's Tower in Mississippi Canyon, Kerr-McGee's Gunnison in Garden Banks and Murphy Oil's Front Runner in Green Canyon.

Although there are a large number of small fields that will be tied back to existing infrastructure there are few post-2004 large developments. ConocoPhillip's Magnolia may make a 2004 start-up, but 2005 looks more likely. The GoM's largest field, BP's Thunder Horse, comes onstream in 2005. BP's Entrada and Atlantis are for 2006, while Shell's Great White looks a certain development.

Other large accummulations likely to be developed include Agip's Leo, Anadarko's Gomez, BHP's Neptune, ChevronTexaco's Champlain, and Unocal's Trident. GoM production will probably top out in the 2005–2007 period at well over 2mn b/d.

Field name	Oil/gas	Block no	W d'pth ft	Operator	Disc.	Start up	Oil res. (mn b)	Gas res.	Prod. system	Peak prod. (yr)
Viosca Knoll										
Einset	gas	VK 972	3,500	Shell	2001	2002		30bn cf	subsea	60mn cf/d
Ida	gas	VK 1003	4,400	Total	1999	Planning		60bn cf		
North Marlin	oil/gas	VK 827	2,500	Shell	1998	2003	18mn boe			
Swordfish	oil/gas	VK 962	4,000	Mariner En'gy	2002	Planning			subsea	
Thor South East	oil/gas	VK 870	2,379	Oryx	1986	2004	7.5mn boe		subsea to FPS	
VK 862	oil/gas	VK 862	1,040	Walter Oil	Planning				subsea	
Mississippi Canyon										
Aconcagua	gas	MC 305	7,000	Total	Apr-99	2002	60mn boe	400bn cf	subsea via Virgo plat.	Canyon Express project
Ariel (Nakika)	oil/gas	MC 429	6,215	Shell	1996	2004	15mn boe			100k b/d, 325mn cf/d
Camden Hills (CanX)	gas	MC 348	7,200	Marathon	1999	2002		180bn cf		175mn cf/d
Coulomb (Nakika)	oil/gas	MC 657	7,520	Shell	1988	2003				see Ariel
Deimos	oil/gas	MC 806	3,000	Shell	2002	Planning				
Devil's Tower	oil/gas	MC 773	5,600	Dominion	Jan-00	2004	50–70mn b		Spar	60kb/d
Eiger sanction	oil/gas	MC 667	2,934	Anadarko	Jun-05	Planning				
Fourier (Nakika)	oil/gas	MC 522	6,950	Shell	1989	2003			see Ariel	
Gomez	oil/gas	MC 755 +19 other	3,000	Anadarko	1987	Planning	140mn boe		DCU	40k b/d
Goose	oil/gas	MC 751	1,600	Spinnaker	2003	Planning				
Hawkes	oil/gas	MC 509	4,174	ExxonMobil	2001	Planning				
Herschel (Nakika)	oil/gas	MC 520	6,739	BP	1996	2003	50mn boe			see Ariel
Horn Mountain	oil/gas	MC 127	5,400	BP	1999	Dec-02	150mn boe		Spar/Aker Finnyards	70k b/d, 68mn cf/d
Kepler (Nakika)	oil/gas	MC 383	5,700	Shell	1987	2003	38mn boe		FPS	see Ariel
King/King's Peak	oil/gas	MC 84, 85,129	5,365	BP	1993	2002	30mn boe		floating prod.	28k b/d
King's Peak West	oil/gas	MC 217	6,435	BP	1992	2004	15mn boe		subsea to FPS	
Leo	oil/gas	MC 502/3, 546	2,500	Agip	1998	Planning	100mn boe		floating prod.	
Matterhorn	oil/gas	MC 243	2,875	Total	Aug-99	late 2003	90mn boe	30bn cf	Seastar TLP	40k b/d, 55mn cf/d (04)
Medusa	oil/gas	MC 582	2,200	Murphy	1999	2003	100mn boe		Truss Spar	
Metallica	oil/gas	MC 911	7,000	BP	1997	2004				
Mirage (ex Zeus)	oil/gas	MC 941	3,905	BP	1999	Planning	100mn boe		FPS or subsea	
Morgus	oil/gas	MC 942	3,957	Shell	1999	2003		25bn cf		33k b/d, 55mn cf/d
Narcissus	oil/gas	MC 630	4,250	ChevronTexaco	1997	Planning				
Nirvana	oil/gas	MC 162/3	3,520	BP		Planning				
Nakika*	oil/gas	MC 474, 520	6,739	Shell		4Q2003	150mn b	300mn boe	FPSS	100k b/d, 325mn cf/d
North Gemini	oil/gas	MC 248	3,290	ChevronTexaco		Planning			subsea	
Princess (subsalt)	oil/gas	MC 765	3,600	Shell	Jul-00	2003	over 200mn boe		close to Ursa	
Seventeen Hands	gas	MC 299	5,450	Murphy	2001	Planning		80bn cf		
Thunder Horse	oil/gas	MC 778	6,000	BP	Jul-99	1H2005	1.0mn boe		PDQ semisub	150k b/d
Thunder Horse (N)	oil/gas	MC 776	5,640	BP	2000	1H2005	500mn boe			
Timber Wolf	oil/gas	MC 555	4,750	ExxonMobil	2001	Planning				
Triton	gas	MC 772	5,570	ChevronTexaco	1999	Planning		60bn cf		
Venus	oil/gas	MC 853	3,755	Shell	1992	2002	30mn boe		subsea to FPS	
Zia	oil/gas	MC 496	1,780	Ocean Energy	1998	2003	30mn boe		subsea to fixed plat.	15k b/d
Green Canyon										
Aspen	oil/gas	GC 243	3,100	BP	2001	2002	40mn boe		subsea via BP's Troika	30k b/d, 30mn cf/d
Atlantis	oil/gas	GC 778	7,000	BP	Q2-99	3Q2006	635mn boe		Drilling & Prodn semis	150k b/d
Bison	oil/gas	GC 166	2,500	ExxonMobil	1986	2003	50mn boe		FPS or subsea	
Fuji	oil/gas	GC 562	4,269	ChevronTexaco	1995	no plans	60mn boe		Floater/FPSO (1st)	
Front Runner	oil/gas	GC 338	3,500	Murphy Oil	2001	2004	120–150mn boe		Spar	60k b/d, 110mn cf/d
Front Runner (S)	oil/gas	GC339	3,500	Murphy Oil	2001	2004	60–80mn boe			
GC 228	oil/gas	GC 228	1,730	Noble Energy	1985	Planning				
GC 244 (Jedi)	oil/gas	GC 244	1,750	Kerr-McGee	2001	Planning	40mnboe			
GC 37	oil/gas	GC 37	2,024	British Borneo	1997	2002	5mn boe		subsea to FPS	
GC 82	oil/gas	GC 82	2,400	British Borneo	1996	2002	4mn boe		subsea to Fixed platform	
Glider	gas	GC 248	3,300	Shell	1996	Planning		120bn cf	subsea to Brutus	

Deepwater fields in Gulf of Mexico

Field name	Oil/gas	Block no	W d'pth ft	Operator	Disc.	Start up	Oil res. (mn b)	Gas res.	Prod. system	Peak prod. (yr)
Grand Canyon	oil/gas	GC 141	1,715	Conoco	1987	2003	15mn boe		TLP	
Gretchen	gas	GC 114	2,130	Devon	1999	Planning	40mn b	40bn cf	subsea tieback to Brutus	
Holstein	oil/gas	GC 644	4,400	BP	Q2-99	2004	275mn boe		Spar	100k b/d
Hornet	oil/gas	GC 378	3,700	Kerr-McGee	2002	Planning				
King Kong	oil/gas	GC 472/3, 517	3,817	Mariner En'rgy	1997	2002	250mn boe		FPS + subsea	150mn cf/d
K2/Timon	oil	GC 562	3,960	Anadarko	Sep-99	2004	80mn b		tieback to Marco Polo	
Mad Dog	oil/gas	GC 826	6,700	BP	Apr-99	2004	200–450mn boe		Spar	80-100k b/d, 40mn cf/d
Manatee	oil/gas	GC 155, 156	1,950	Shell	1998	3Q2002	12mn boe		subsea to Angus/Bullwin	25k b/d
McKinley	oil/gas	GC 416	4,020	ChevronTexaco	1998	no plans	130–220mn boe			
Marco Polo	oil/gas	GC 608	4,675	Anadarko	Apr-00	1Q2004	220mn boe		TLP cap 100k b/d	50k b/d, 100mn cf/d
Mighty Joe Young	oil/gas	GC 737	4,400	Mariner En'rgy	2000	Planning			subsea	
Poseidon	oil/gas	GC 691	4,489	Dominion	1996	Planning	200mn boe			
Quatrain	oil/gas	GC 382	3,500	Murphy	2002	2004	30mn boe			
Sangria	gas	GC 177	1,500	Spinnaker	1999	2002		30bn cf		
Shenzi	oil/gas	GC 654	4,400	BHP	2002	Planning				
Tahiti	oil	GC 640	4,020	ChevronTexaco	2002	2007	500mn boe			
Yosemite	gas	GC 516	3,900	Mariner En'rgy	2001	2002			subsea	150mn cf/d
Alaminos Canyon										
Baha	gas	AC 600	7,620-8,255	Shell	1996	Planning	50–150mn b			
Great White	oil/gas	AC 857	8,000	Shell	2002	Planning	500–600mn boe			
South Diana	oil/gas	AC 65	4,852	ExxonMobil	1997	Planning	included above		tiebacks to Hoover/Diana	
Trident	oil	AC 903	9,687	Unocal	Jul-01	Planning	340–850mn boe			
Desoto Canyon										
King's Peak No 1	oil/gas	DS 133, MC 217	6,540	BP	1993	2003	250mn b		tie-back to Desoto177	
King's Peak East	oil/gas	DS 133, 177	6,461	BP	1993	2004	25mn boe		subsea to FPS	
Atwater Valley										
Champlain	oil/gas	AT 63	4,305	ChevronTexaco	2000	Planning	170mn boe			
Cyclops	oil/gas									
AT 8	oil/gas	AT 8	3,100	Shell	1991	2004	12mn boe		no plans	
Merganser	gas	AT 37	7,800	Kerr-McGee	2001	Planning		200-400bn cf		
Neptune	oil/gas	AT 575	6,220	BHP	1995	Planning	100mn b		FPS + subsea	
Black Widow	oil/gas	AT 1	2,421	ExxonMobil	1986	2004	12mn boe		no plans	
Turnberry	oil/gas	AT 92	3,400	Dominion	2001	Planning				
Vortex	oil/gas	AT 261	8,344	BHP	2002	Planning				
Ewing Bank										
Ewing Bank 921	oil/gas	EW 921	1,700	British Borneo					mini TLP	
EW 1003	oil/gas	EW 1003	1,700	El Paso	1999	2003			subsea to FPS	
Garden Banks										
244	oil/gas	GB 244	1,983	Kerr-McGee	1997	2002	12mn boe		FPS or subsea	
254	oil/gas	GB 254	1,920	ChevronTexaco	1993	2004	12mn boe		no plans announced	
302	oil/gas	GB 302	2,400	Conoco	1991	2003	8mn boe		FPS	
Dawson	oil/gas	GB 669	3,000	Kerr-McGee	2001	Planning				
Devils Island	oil/gas	GB 344	2,300	Amerada Hess	2002	Planning				
Durango	oil/gas	GB 667	3,150	Kerr-McGee	2001	2004	120bn cf		subsea	
Entrada	oil/gas	GB 782	4,642	BP	2000	2006	150mn boe			30k b/d, 110mn cf/d
Gunnison	oil/gas	GB 668	3,120	Kerr-McGee	Jun-00	1Q2004	150–250mn boe		Spar	40k b/d, 200mn cf/d
Habanero	oil/gas									
Jason	gas	GB 344	2,400	EEX	2000	Planning		20bn cf	subsea	
Knight	oil/gas	GB 372	1,740	Devon	1997	Planning	11mn boe			
Ladybug	oil/gas	GB 409	1,355	ChevronTexaco		go ahead				
Llano	oil/gas	GB 385,386	2,700	Shell	1998	2Q2004	40mn boe		2 subsea to Auger TLP	25k b/d, 74mn cf/d
Magnolia	oil/gas	GB 783, 784	4,700	Conoco	Jan-99	4Q2004	150–200mn boe		DCU to Auger field	50k b/d, 150mn cf/d
Ozona Deep	oil	GB 515	3,280	Marathon	2001	Planning	100mn b			
Red Hawk	gas	GB 877	5,300	Kerr-McGee	2001	2Q2004			300–500bn cf	120–300mn cf/d
Salsa	oil/gas	GB 171	1,076	Amerada					Plat. via Enchilada	
East Breaks										
Boomvang	oil/gas	EB 643, 688	3,800	Kerr-McGee	1996/97	mid 2002	35–50mn boe	200bn cf	Spar on EB643	30k b/d, 200mn cf/d
Falcon	gas	EB 579	3,400	Pioneer	2001	2003		150–250bn cf	subsea	175mn cf/d
Hack Wilson	gas	EB599	3,000	Burlington Resrs	2001	Planning		40bn cf		
Harrier	oil/gas	EB 759	3,400	Pioneer	2003	2004				
Horseshoe (SW)	gas	EB 430	2,280	Amerada Hess	2000	Planning		30bn cf		
LaSalle	oil/gas	EB 558	3,415	Anadarko	2001	Planning			subsea	
Lost Ark	gas	EB 421	2,700	Noble Energy	2001	2002		200bn cf	subsea	40mn cf/d
Marshall	oil/gas	EB 949	4,380	ExxonMobil	1998	1Q2002	15mn boe	28bn cf	tieback to Hoover/Diana	
Nansen	oil/gas	EB 601/2/46	3,600	Kerr-McGee	1999	mid 2002	120–160mn boe	230–600bn cf	8 wells to Spar on EB	40kb/d, 200mn cf/d
Navajo	oil/gas	EB 690	4,100	Kerr-McGee	2001	2002	30mn boe		subsea	50mn cf/d
Navajo (W)	oil/gas	EB 689	3,700	Kerr-McGee	2002	2003	30mn boe		subsea	
Navajo (NW)	oil/gas	EB 646	4,000	Kerr-McGee	2002	2003	30mn boe		subsea	
Rockefeller	oil/gas	EB 992	4,820	ExxonMobil	1996	Planning	10mn boe	50bn cf	possible development	

**(Nakika project which includes Ariel, Herschel and Keppler)*

Deepwater fields in Gulf of Mexico

Tesco Stores recently opened at Ramsgate, Kent, what is believed to be the first service station in Europe to utilise above ground petrol storage tanks, reports *Rory Hennessy*, Fire and Petroleum Risk Manager.

Above ground fuelling first for UK superstore

An above ground tank solution was selected at the site in Ramsgate, Kent, due to its position above a Zone 2 aquifer and close to adits [channels] in the chalk. It had been estimated that any contamination from the service station would impact the water table in a matter of hours and, as a result, the Environment Agency (EA), through the local authority planning process, had objected to any fuelling facility being sited at this location.

An original scheme offering a double-skin tank with double-skin pipework was refused, as was a later proposal with the double-skinned tanks being installed in a monitored vault. In order to reconsider any proposal to site a service station at the Ramsgate location, the EA laid down challenging criteria that had to be met before it would support a further planning application.

These included:

- Above ground tanks
- Double wall pipework
- Prevention of surface spills migrating through the chalk
- High levels of monitoring

Tanks from the US

Until the late 1990s above ground fuel storage tanks had only been of a size that lent themselves to small use in private installations. However, changes in US environmental legislation went on to drive the market to above ground tanks of larger capacities.

The US specification tanks selected


Top: The finished Tesco service station with the tank storage facility in the background. Above left: the foundations for the above ground storage tank being laid. Right: installation of the tanks

Above left: the framework of the building housing the tanks. Right: inside, the tanks are marked with their relevant content

for the Ramsgate fuelling facility were sourced from Ledbury Welding, who recently secured a UK licence for Supervault tanks (see *Petroleum Review, Retail Marketing Survey,* March 2003). The Supervault tanks offered a four-hour fire rating, ballistic testing, monitored double-skin and, most importantly, came in capacities that met the then Tesco design requirements for the four 45,000-litre tanks required for a six-dispenser site.

Although being double-skinned and monitored, the EA additionally wanted the tanks to be sited in a bund, to contain any unforeseen spillages. In order to meet visual planning requirements the tanks were also required to be housed in a suitable structure to blend in with the superstore. Fire-treated, close-boarded timber walling with a steel trussed roof and slate tiles was constructed. Provisions were also made in the roof to be able to remove tank probes and internals when maintenance is required. A steel walkway was provided for easy access.

As Tesco's road tankers have no pumping-off facility, static positive-displacement electric pumps have been installed at the site. Electronic overfill prevention is also provided to shut-off the transfer pumps in the event of an overfill. Pumping rates provide a seven-minute offloading time much favoured by the delivery drivers.

The EA was prepared to accept double-wall pipework with constant monitoring. All the systems currently available on the marketplace were evaluated, with Total Containment being the final chosen solution. The decision was driven by the need not to disturb the installed structural prevention on site. Easy retractability of the inner pipe in the event of a future re-piping was therefore essential.

Tackling spills

The issue raised by the EA of surface spills on the forecourt and the tanker offloading area passing into the chalk layer are addressed in two ways over and above the provision of a surface drainage system.

The primary defence against surface spills migration is to lay a continuous bitumen/resin forecourt surfacing material to the refuelling area, tanker bay and above ground tank bund. The selected Danish product was Densiphalt – which requires no expansion joints and is laid in one continuous layer.

In the unlikely event that spillages do reach the layer below forecourt level a second means of prevention is provided. A petrol-resistant membrane is located below pipework level and extends under the forecourt, tanker offloading area and the tank bund. The membrane was thermo-welded and fabricated on site. It provides upstands at all vertical structural members, such as dispenser islands, canopy columns, tank bund walls and boundary curbing. The membrane is not drained but is intended to collect any leakage that passes through and for product to degrade naturally. The membrane is one used in the US to form temporary open bunds for crude oil storage.

Pipework in the tank farm is provided with isolation valves, while the dispensers are provided with excess flow valves and dispenser shear valves to prevent siphoning due to the static head pressure of the above ground storage.

All leak alarms for the pipework, sumps, tank interstitial space and the tank bund are monitored in the kiosk, with dispenser shutdown in the event of a detection. All the alarms are linked back to Tesco Stores' 24-hour central security monitoring station at Cheshunt to ensure no alarms remain unattended to at the local level.

The provision of three observation wells was scaled down to one, in agreement with the EA, after the first well needed to be drilled to 85 metres before the water table was reached! The need for and the risk associated with presence of the wells was debated at length with the EA. My own personal view is that the wells provide a direct route for pollution to the water table – but the greater benefit of quicker action on remediation prevailed from the EA's perspective.

The Ramsgate facility was built in just eight weeks, constructed to target and completed on schedule. It is interesting to note that the tanks were installed at the end of the programme, unlike a conventional build.

The site is now operational and we anticipate throughput of some 7mn/y of fuel. While above ground tanks are not the cheapest option for fuel storage at the forecourt – costing some three times more than conventional storage solutions – they are a viable solution where environmental conditions dictate.

The future of UK energy to 2050

Azfar Shaukat of Capital Energy and *Gill Ringland* of the St Andrews Management Institute (SAMI) **demonstrate the relevance of 'scenario planning' to the energy sector and discuss the outcomes derived from scenarios developed during a workshop at the Strategic Planning Society to consider the UK's future energy needs. Although the workshop was too short to be anything other than illustrative of the process and possible outcomes, the group developed significant insights that surprised the 'experts'.**

What will be the UK's energy needs in 2050 and how will they be met? At first glance this seems an impossibly daunting question to answer. Future political, technological and social possibilities seem unbounded and, as history shows, far-reaching changes can occur in an instant. The energy industry faces such rapid change and discontinuities that shorter-term plans quickly become obsolete.

The pace of change itself seems to be accelerating so forecasts on any timeframe beyond perhaps three years would become increasingly unreliable. Clearly, the question needs to be asked and is of interest to government, utilities and many other bodies involved in long-term energy planning. 'Scenario planning' can help answer the question.

Scenario planning process

Long-term forecasting is an essential element of planning and strategy development in the energy sector. Companies, ministries and other interested groups seeking to look 'over the brow' need tools to help them plan for longer planning horizons. Many different approaches have been tried, ranging from little or no planning beyond the immediate corporate plan, to rigid analytical approaches, to much more qualitative 'brainstorming' methods. Traditional methods of long-term planning have used various empirical (eg extrapolation), algorithmic (eg 'tuned' extrapolation), statistical (eg Monte Carlo analysis) and 'blue sky' (eg 'crystal ball') methods to narrow down future options.

Scenario planning as a business tool has been practised since the early 1970s, when Shell's Pierre Wack demonstrated its potential by helping Shell's managers prepare for the mid-70s and mid-80s oil crises. The technique is now a well-known, and well-practised, planning tool in major energy companies to provide early warning, identify new opportunities and reduce risks.

Scenario planning is not about forecasting definite outcomes, rather it is a technique that helps identify combinations of possible events in the future that will be critical and will need to be watched for. Other events occurring outside this 'envelope' are called 'wild cards' and it is these events which, if they happen, require emergency reaction. Developing potential responses to events within the envelope should then provide meaningful strategies that will be cognisant of the most critical events.

As shown in **Figure 1**, various planning tools can produce quite diverse projections. Scenario planning will allow focus on a specific set of events of interest and help identify their possible relevant impact.

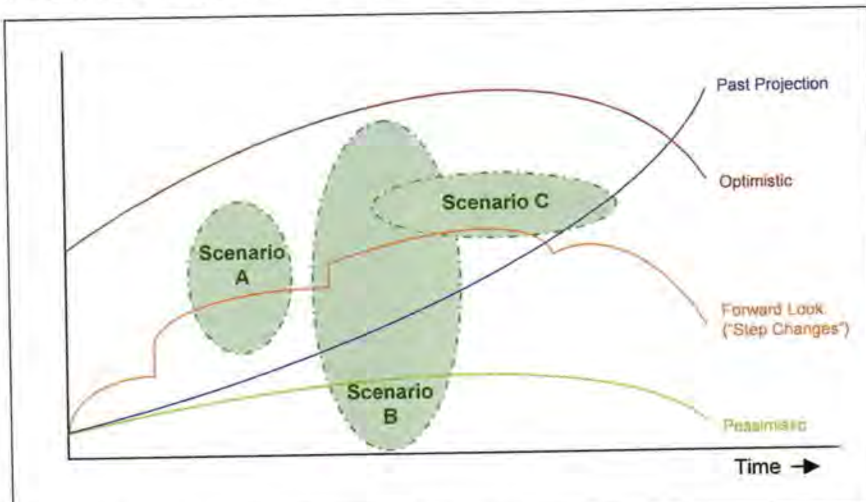


Figure 1: Example growth projections using various techniques

Scenario planning workshop

Our workgroup at the Strategic Planning Workshop comprised a wide cross-section of industries, backgrounds and experience levels. They had been briefed by reading several background papers including draft government papers. The scenarios were developed in a single session – in reality there would be several sessions examining in more detail many facets highlighted in the first session.

The process involved:

- Defining the area of concern, in this case the UK energy environment in 2050.
- Identifying the external as well as the internal driving forces shaping this environment.
- Understanding the critical uncertainties and risks.
- Sorting the broad range of outcomes and events into forecastable and uncertain, important and unimportant events.
- Identifying three groups of uncertain and important events.
- Generating scenarios from these three groups.

For each scenario the aim was the understanding of any early indicators, enablers, likely culture, and timeline that would affect the UK energy picture in 2050.

We had originally posed the question as: 'What will be the dominant form of power generation for the UK in 2050?' One of the interesting outcomes was that two of the scenarios (see right) postulated that because of possible technology breakthroughs, in better storage and transmission of electricity in particular, the question was less relevant since power could be imported and we could be independent of its source or generation mode.

Three plausible UK futures

Three plausible future scenarios were postulated (see **Figure 2**) – 'Cheap Future', 'Village Green' and 'Brave New World' – each of which is outlined to the right. These results are not meant to be definitive or complete, but rather illustrate the scope of issues covered in developing scenarios and assessing their impact. A comprehensive scenario analysis is likely to consider many more drivers and scenarios and take much more planning effort.

Critical Drivers	Scenario		
Storage & Transmission	New Technologies	Current	New Technologies
Power Generation	Current	New Technologies	New Technologies
Government Focus	Economic	Social	Economic
	"Cheap Future"	"Village Green"	"Brave New World"

Figure 2: Three plausible UK future scenarios were postulated by the workshop

Critical Enablers
- New storage and transmission technologies
- Generation at fuel source
- Imports of power
- Storage reduces emphasis on generation capacity
- New energy management approaches

Timeline
- Short-term electricity price rise because of dependence on imported fuel
- 10–20 yrs: electricity generated abroad and delivered to UK
- Foreign companies may develop cheaper electricity routes to UK

Government may find that they are forced to have an economic policy focus

Opportunities for new electricity storage and transmission

Scenario 1 – 'Cheap Future'

Critical Enablers
- New forms of power generation
- Culture
  - Parochial, 'Middle England'
  - Small-scale and local, self-sufficient
- Local subsidies

Timeline
- 2010: Reducing fuel poverty; subsidies; technology prototypes
- 2020: Technology prototypes economic; change in usage
- 2025: Rollout of community infrastructure
- 2030: Investment in new technology
- 2040: Second generation technologies

Government likely to have social focus

Opportunities for local generation, renewables technology, district heating

Scenario 2 – 'Village Green'

Critical Enablers
- Fuel cells for limitless storage
- Near-zero transmission losses
- Many new forms of generation (eg renewables, safe nuclear, hydrogen, local generation)
- Culture
  - Entrepreneurial; individualistic; technologically advanced
  - Consumer driven; market orientated

Timeline
- 2008: No new oil or gas finds drive electricity prices up
  Political insecurity outside Europe drives prices up
- 2015: Technology breakthroughs, interventionist government changes distribution, funds R&D
- 2025: Non-interventionist government

Government likely to have social focus

Scenario 3 – 'Brave New World'

Taken individually the three scenarios appear discrete, but viewed collectively common themes begin to emerge that could have far-reaching consequences for government, infrastructure, suppliers and customers.

All the scenarios envisaged increased in electricity prices in the short-term due to increasing dependence on imported fuel. This was due to declining UKCS production, falling reserves replacement and increasing costs of getting new finds to market, and political uncertainty over the next five years and beyond.

The profound effect on the energy landscape of new transmission technologies became apparent. Cheaper energy imports through lower cost bases or generation at source overseas would reduce the need for own-generation. This would mean less demand for fuel, impacting the natural gas and coal industries. For gas it could relieve imports through existing or future inter-connectors but would also deeply affect revenues, since power generation is expected to comprise over 50% of gas consumption by as early as 2010.

Some as yet undiscovered means to store electricity could have a similarly dramatic effect on the gas industry. Power storage would vastly increase the attractiveness of renewables and allow seasonal or more frequent arbitrage with imports. This would change the rules of the game for the power industry.

In the future, gas imports could place further pressure on the economics of coal and raise critical security of supply issues. The coal industry could be providing more secondary gas through new conversion processes as well as primary fuel for generation.

The scenarios also showed that if these technology breakthroughs do not occur then rising costs of 'traditional' generation, transmission and distribution in the future may encourage much more of a 'village' environment, with local generation and captive customers with high inertia. This environment could also be encouraged if future oil and gas becomes so expensive that road travel and therefore logistics was drastically curtailed.

Such impact on supply and the energy industry may force a rethink on the extent of open competition and access to UK markets. In the extreme case there could even be a reversion to partial or complete nationalisation. In two out of the three scenarios, the government's focus was social rather than economic. It would be interesting to examine how the government could sustain an economic perspective under these conditions.

Clearly, the range of issues identified through these scenarios is vast and their effects on stakeholders will be similarly diverse. Further sessions can be used to home-in on specific issues of interest and develop their potential impact in more detail.

Key learnings

As noted earlier, these scenarios were prepared in limited time and were not meant to be comprehensive. Additional preparation, research and specialist input would have helped in the detail, but we found that credible and meaningful ideas could be produced even in a short but focused scenario creation session.

Some additional learning points to make the process more effective are summarised below:

- Scenario planning is best carried out by considering the widest possible sources of input, often through interviews.
- A team of well-prepared specialists under effective facilitation is needed to build the scenarios.
- Preparation and background research are focused by the initial data input.
- Absolute accuracy is not the aim and there is an extent beyond which the broad outcomes from each scenario are not materially affected by the level of detail.
- Cross-disciplinary input can generate a broader spectrum of ideas and 'angles' than from sector-specific specialists only.

Forward-looking approach

The example demonstrates how scenario planning can be used to help organisations look beyond their traditional planning methods and prepare themselves for a wide range of future eventualities, some predictable, others not. This long-term view can influence investment decisions, corporate development and growth to maintain an organisation's momentum and avoid costly 'U-turns'.

Forward-looking companies recognise the potential impacts early and begin thinking about their state-of-readiness for such events and how they could be better prepared. Through this process they develop flexible and responsive strategies and reduce the likelihood of being wrong-footed in an increasingly uncertain future.

...continued from p2

years. According to a new report from the consultant Wood Mackenzie, Venezuela is unlikely to be able to invest enough to maintain production capacity and is now set to join Indonesia and Qatar as Opec producers in decline.

The real challenge comes at the point when the additional volumes from the countries where production is expanding is fully offset by the loss of production from the countries where production is declining. Then global production will be in decline.

By focusing attention on the 'good news' of new production growth and minimising attention on the expanding areas of production decline the industry has failed to recognise that the 'great rollover' as it is sometimes called will occur within the next half-generation. In historical terms a half-generation is tomorrow.

However, the major oil companies have made a radical shift towards gas production and already we have little short of boom in LNG developments, with new trains either planned or under construction at all the existing centres. The US is set to become a major LNG importer, with over 15 current applications to build LNG import terminals. Great hopes are placed on gas-to-liquids and the first large-scale plant is now due to built in Qatar. Its importance is that it essentially moves GTL from targeting the high-value speciality products, which is how the existing small plants are rendered economic, to targeting the bulk market for high quality oil products – which is how the new large plants will be made economic.

The news that the UK Government is planning some of the largest wind farms in Europe suggests it is taking the impact of oil depletion seriously. However, with even the best located wind farms only generating power for 35–40% of the time and wind generation costs still being twice those of more conventional generating costs, many questions remain.

At the moment the UK Government's action may be a courageous decision showing great foresight or it may be the greatest government folly since the ground nut scheme of the 1950s. At present we really don't know which, although more broadly based energy research may provide some answers.

The new Energy Institute is ideally placed to help answer some of these questions about viable alternatives.

At the moment there is only one course of action for governments and consumers to take that minimises future supply risks, investment misallocation and mistiming. That action is always to invest in the most fuel efficient technology available as the risks in doing this are lower than for any other course of action.

Chris Skrebowski

Local content agreements – do they work?

The governments of oil and gas producing countries often attempt to improve their self-reliance and gain a higher share of the value from oil and gas projects by negotiating local content agreements with the interested operating company. *Mojgan Djamarani* looks at how the issues that arise from such agreements have been addressed in a number of countries to see if they have achieved their objectives.

It is now widely argued that the development of oil and gas resources in the developing countries has failed to lead to their economic development. Foreign investment in the sector has not led to the transfer of knowledge and technology that was expected of it.

The blame has been laid as much on the foreign oil companies, whom it is argued are indifferent to whether local economies receive any benefits from their investments, as on corrupt governments to whom oil revenues accrue. A topical case in point would be the recent community unrests in the Niger Delta region.

To assuage rising local discontent a number of governments are raising, as well as insisting on a minimum level of local content in their oil contracts. The issue is a very country specific one as different countries are at different stages of economic development.

Kazakh success

With local content, money is injected directly into the local economy. According to Martin Raiser, Director for Country Strategies and Analysis at the European Bank for Reconstruction and Development (EBRD), where a minimal basis for local SME (small–medium enterprise) development is absent insistence on minimum local content is the wrong policy – it is inefficient, creates enormous scope for rent seeking and fails to generate true technology transfer.

Kazakhstan and Nigeria provide two contrasting sides to this statement. In Kazakhstan the Vendor Development Programme of both the Karachaganak Integrated Organisation (KIO) and TCO (TengizChevroil) has been particularly successful in increasing the percentage of Kazakh content – rising from less than 25% to 64% of value in new contracts in the case of KIO in 2002. KIO estimates that by the time the entire project is complete the Kazakh content of the contracts awarded will be $1.3bn.

The success of the programme can be attributed to the quality, commercial and technical training that it provides the educated labour force and the fact that most of the companies currently operating in the oil and gas field services market in Kazakhstan are spin-offs of the former Soviet-era research institutes. They reportedly provide up to 50% of the oil and gas field services in a market with an estimated value of between $500mn and $800mn. For some projects the Kazakh Government has been able to negotiate agreements so that the operating company has to provide funds for a technical university.

Nigerian investment

Following outcries over the low level of local content in major oil projects – about 5% – the central government in Nigeria in 2002 set a deadline of 2005 for the industry to achieve a minimum of 50%. Backed up by the Bush administration, foreign oil companies are at present very keen to invest in Nigeria and the rest of the oil producing sub-Saharan Africa. The region already provides 15% of US oil needs and by further increasing exports from Africa the US administration hopes to reduce dependence on Middle East oil. Sub-Saharan Africa is also attractive to international oil companies because, with the exception of Nigeria, the other producers are not members of Opec. Even more importantly a lot of the oil discoveries lie offshore and away from local communities.

The oil companies, forever mindfull of their public image, on the face of it seem to be going along with demands for increased local content. The clause for increased local content was reportedly responsible for holding up the development of the $1bn Agbami offshore oil field owned by the NNPC/ChevronTexaco joint venture. This issue has now been settled so that 30% ($1.2bn) of the total $4bn expenditure cost for the three oil and gas projects that include the development of Agbami goes into the Nigerian economy. Earlier this year ChevronTexaco brought in 10 foreign companies to explore the possibility of establishing fabrication yards in Nigeria while Shell Nigeria claims to have a target of 35% Nigerian content to be achieved annually in its contracting for goods and services. However, it is the lower skilled work category contracts that go to Nigerian contractors.

Already the Nigerian Government is requiring that about 25% of fabrication contracts for all oil projects be executed in Nigeria. It is difficult to see how this can be achieved considering that by the end of the 1990s the manufacturing industry accounted for just 5.5% of the GDP, while the average was 15% in the low and middle income countries in Sub-Saharan Africa. In the mid-1990s the manufacturing sector provided less than 3% of export earnings and employed about 300,000 people.

A question of sincerity

As expected by the EBRD and according to the Petroleum Technology Association of Nigeria (PETAN) in March 2003, the multinational service providers have resorted to creating bogus companies to fill the local content requirement. The Association also accuses the international oil companies of engaging in predatory pricing of contracts in the upstream sector to the detriment of indigenous service providers. This raises questions over the sincerity of the international oil companies' commitment to meet increased local content. PETAN also questions the seriousness of the Nigerian Government's commitment to the issue by pointing out that indigenous service providers have to pay full custom duty for the tools they import into the country while their multinational counterparts enjoy a waiver on import duty.

William Dor, the head of Global Industries, in a recent article in *World Energy* magazine also questioned the practice of demanding that local labour and content be employed in exploration and drilling projects, claiming that substandard quality leads to unsatisfactory results. Development of in-country capabilities and infrastructure is a long-term process and in the meantime Dor is calling for a universal standard of risk assumption – ie all parties, including the local government enforcing the local content agreement, should be subject to a 'reasonable risk/reward matrix with a profitable outcome for both'. In turn, this should mean that if the project suffers from the local content agreement then the local government should also have to endure its share of the downside.

Photo: Sibneft

In Russia, some 80% of the workforce in a PSA must be comprised of Russian employees, while at least 70% of the total cost of all orders to manufacture equipment and materials must be allocated to Russian firms or foreign firms that are registered as tax payers in Russia.

Indonesian percentages

Including local content clauses in oil contracts does not mean that it is actually achieved. In the case of Indonesia, for example, the government expects all oil and gas companies to use a minimum local content of 35% – but in practice, given the quality standard set by the oil majors, the local content level ranges between 10% and 20%.

Recently protests broke out over state oil and gas company Pertamina's outsourcing policy, which the small local firms saw as intending to put them out of business in favour of foreign players with large capital. This led to a new oil and gas bill proposed by the government earlier this year, which seeks to lift the monopoly held by Pertamina over the country's oil and gas business.

Strategy in Iran

In the case of Iran, local content is of more strategic interest. The Oil Ministry has been pushing for Iranian oil companies to take over projects as prime contractors. The level of local content has been pushed up from 30% in 1989 to 40% in 2000, and 51% in 2001.

The problem in Iran is that, in spite of continuous government support and supply of resources into the manufacturing sector, it has not gained the capability it needs for a sustained growth. The real average annual rate of growth for manufacturing value added in the 1980–1998 period was 4.7% compared to 11.7% in the decade before the Islamic Revolution. It does not compare favourably with the 9.3% for South and East Asia and 7.3% for developing countries as a whole. Therefore, the emphasis in local content has been on capacity building in local industries by obliging foreign operators involved in subcontracting and equipment manufacturing to transfer their technologies to their Iranian partners. To ensure that local content is maximised Iran has introduced penalty clauses. In the Darkhovin project, for example, if the contractor is not able to meet the minimum 30% local content it will be penalised 50% to every US dollar.

Russian tax revenues

Local content has tremendous impact on the national economy, not just by creating jobs or transferring new technologies, but also as a generator of tax revenues for the government. The Russian Government is well aware of this contribution and the production sharing agreement (PSA) law provisions regulating national content requirements have been amended to strengthen the position of the Russian contractors. Some 80% of the workforce in a PSA must be comprised of Russian employees, while at least 70% of the total cost of all orders to manufacture equipment and materials must be allocated to Russian firms or foreign firms that are registered as tax payers in Russia.

Russian Government statistics, as outlined by Chris Viner and Alexey Amvrosov of the Moscow office of Rose International Law Firm, put the involvement of Russian contractors in PSA projects at less than 60%. Currently there are no penalty clauses for non-compliance. However, the new amendments propose that the investors' production volume, otherwise representing cost oil, be decreased by double the cost of the goods that should have been, but were not, purchased from a local source. The proposed amendments also call for price to be included as one of the criteria for selecting equipment and materials. This will obviously favour Russian contractors in any competitive bid. But Viner and Amvorosov point out that some members of the Russian Duma want to ge even further and follow the Brazilian model where legislation specifically prohibits 'goldplated' solutions where unnescessarily high specifications are used to exclude local suppliers.

Local content is not written in stone.

According to Todd Crossett, co-founder and partner of Sakhalin-Alaska Group and who also facilitates the development of joint ventures between western companies and Russian firms: 'Each project has its own working description of, and differing philosophies on, Russian content.' The criteria are constantly changing in relation to the Russian political and regulatory scene as well as project parameters and strategies. Therefore, 'the proper approach for the contractors is always changing'.

Bankers' attitude

Intrusive government policies to increase local content in ways that are not economically favourable to foreign investors can create problems in the financing of oil and gas projects. The European Union (EU), which is the largest source of foreign direct investment (FDI) in Kazakhstan, recently warned against the flow of new regulations in the country that run against the principle of national treatment for EU companies as set out in the PSAs as harming the investment climate.

According to Roger Gott, Director of Oil and Gas Division at Export Credits Guarantee Department (ECGD) 'If a project has a high-level of foreign or local content, it may increase the risk. Essentially it is up to the project sponsor and the contractor to ensure that this risk is mitigated'. This could be done for example by sourcing some of the financing locally. In Nigeria at the beginning of the year six Nigerian banks for the first time underwrote $160mn local content element in the NLNG Plus project. As a rule, provided a project has 100% financing irrespective of source, Gotts explains, 'ECGD can support financing for up to to 85% of the UK content, and up to 15% of the contract value in respect of local and other foreign costs – the figure is higher where there are EU sub-contracts, or where we can apply reinsurance arrangements.'

Virtuous circle

Setting unachievable high levels of local content can defeat the object of the exercise because, in most cases, local companies either do not exist or they are substandard to their foreign counterparts. This has led to conflict between the operating company and the local economy.

However, there are examples like Kazakhstan where the policy seems to be working, and already Kazakh engineers and the general oil and gas workforce have acquired a good reputation for competence and reliability. This is likely to lead to a virtuous circle where foreign operating companies will be happy to increase their local content which, in turn, will lead to more local experienced engineers, thus reducing the need to fly in expensive ex-pat engineers who would consider places like Kazakhstan as hardship locations.

In the longer term, the best indication of how well local content has helped to develop self-reliance is when engineering companies and consultancies from oil and gas producing countries start to compete worldwide with those already established, usually from the same countries as the large operating companies. ●

Pushing the envelope of subsea pipeline design

INTEC Engineering, a division of the Heerema Group, completed detailed design this spring of some 330 miles of deepwater pipeline and associated subsea equipment for the installation of the BP-operated Mardi Gras transportation system planned for the Gulf of Mexico. *John Stearns*, INTEC's Project Director, reports on what is claimed to be the company's largest, most complex project undertaken to date.

A pipeline end terminal (PLET) for the BP-operated Mardi Gras project undergoes system integration testing (SIT) at the Omega yard in New Iberia, La.

The Mardi Gras pipeline transport system is proceeding on schedule, with pipeline installation commencing in November 2002. The installation plan calls for several phases, the first of which is the largest with all the oil and gas pipelines initially commencing in southern Green Canyon. Pipelines ranging from 16 inches in diameter to a record 28 inches in diameter are destined for water depths ranging between 4,300 ft to 7,250 ft. As of June 2003, more than 50% of pipe was installed. Installations using Heerema's *Balder* heavy-lift semi-submersible barge – newly converted to accommodate the J-lay method – will continue through 2004.

Complex project

The contract for the design/engineering, procurement and installation support for the Mardi Gras subsea system from deepwater host facilities to shallow-water platforms is INTEC's largest and most complex project to date. At peak, we have dedicated up to 100 people to the project – a project that is pushing the envelope for subsea pipeline design.

Although using proven technologies, the company is also doing things that have never been done in these ultra-deep waters while creating avenues for new infrastructure and future deepwater tie-ins. The most critical part of the design are the steel catenary risers (SCRs) – two for each of the four deepwater floating host platforms for a total of eight gas and oil SCR installations to accommodate both gas and oil production.

The challenge is designing the SCRs to address fatigue due to phenomenon such as vortex-induced vibration from the floating structures – two spars and two semi-submersibles. Risers measuring 16 inches to 24 inches in diameter will be suspended from the platforms using flex joints. Strakes, spiraling down each riser, are then planned to substantially reduce the SCR vibration to manage fatigue.

Equally challenging are the subsea connections between the main pipelines and laterals which incorporate piggable wye sleds and jumpers. A total of 20 sleds – some weighing as much as 110 tonnes and measuring approximately 60 ft by 20 ft – are planned, with asymmetrical vertical wyes selected for the subsea tie-ins to allow bi-directional pigging of the main pipeline during commissioning. Multi-diameter wyes planned for the tie-ins also will accommodate the varying sizes of the pipeline.

Stringent testing procedures and system integration tests (SIT) are being undertaken on all the equipment to ensure its reliability for the ultra-deepwater.

Pigging is a vital component of the flow assurance plan, with specially designed pigging tools and 'smart' pigs integrated into the complete project scope to measure metal loss and monitor any corrosion that may occur. Pigging challenges include adjustment changes in pipe and equipment diameter; wye geometries and associated subsea jumpers; back-to-back bends; and flow variations.

It is imperative that the pigs are sufficiently robust and durable to withstand the environmental conditions, diameter changes and lengths associated with these pipelines. INTEC is responsible for managing the development of the pigging tools and will support BP in the testing and commissioning of the equipment. The testing process will use a test loop designed with assistance from INTEC. The commissioning programme will include hydrotesting, dewatering and drying, and introduction of hydrocarbons.

Pipeline plans

For the large subsea pipelines, some 120,000 tonnes of steel are planned for the southern Green Canyon area and another 70,000 tonnes of steel are planned for the Mississippi Canyon area. In the southern Green Canyon area, pipelines are planned to transport gas and oil from the Mad Dog, Holstein and Atlantis fields; in the Mississippi Canyon area, pipelines will transport gas and oil from the Thunder Horse field. The scope of trunklines and laterals to develop these fields is complex, with pipeline diameters including 16, 20, 24 and 28 inches.

The Caesar Oil Pipeline System in the southern Green Canyon area includes a trunkline from the Holstein spar to a shallow-water platform at Ship Shoal block 332 in 430 ft of water. A lateral pipeline from the Mad Dog spar ties into the Caesar pipeline; and another lateral pipeline from the Atlantis semi-submersible facility ties into the Mad Dog lateral.

The Cleopatra Gas Gathering System, also in the southern Green Canyon area, is similar in configuration to the Caesar Oil line, consisting of a trunkline from the Holstein spar to the Ship Shoal facility, with laterals from Mad Dog and Atlantis tying in.

In the Mississippi Canyon area, the Proteus Oil Pipeline System begins with a SCR at Thunder Horse and transitions to a larger diameter trunkline to a new-build shallow-water platform at South Pass block 89E in 400 ft of water. Also in Mississippi Canyon, the Okeanos Gas Gathering System consists of a lateral from Thunder Horse plus the main trunkline, which starts at NaKika and terminates at the Destin shallow-water platform on Main Pass block 260.

The pipelines are designed with constant outside diameters – except for the jumpers and wye sleds – in order to reduce the cost of pipe manufacture, for ease of installation and to standardise subsea repair equipment. Where possible, the project team has adopted special design measures to streamline the internal bores of bends, jumpers, subsea connectors and valves. These measures are intended to reduce the operational risks of using pigs on a project of this complexity. The major challenges for the pig operation include multi-diameter asymmetric wyes and long-distance export pipelines.

Proving design viability

Before design could get under way for the mammoth project, INTEC assisted BP in confirming the viability of installing and operating large-diameter pipelines in the Gulf of Mexico's extreme water depths, verifying the design theory and structural reliability for all line pipe material and fabrication tolerances. The companies conducted a theoretical analysis and a full-scale collapse test programme to verify the pipe's resistance to collapse. A full-scale fatigue test programme is also under way to validate the fatigue life of the SCRs.

One of the major concerns during the verification study was the impact of external hydrostatic pressure on the pipelines – ranging up to 3,245 psi in 7,300 ft of water. In the final analysis, INTEC combined BP's multiple requirements with that of the installation contractor and the pipe mills to produce a design that meets international standards.

Top: A 16-inch to 20-inch diameter collet connector running tool being readied for systems integration testing (SIT). Bottom: A pipeline end terminal (PLET) and jumper undergo systems integration testing (SIT)

Balancing reserves acquisitions with drill bit opportunities

***Petroleum Review* is pleased to present the first in a series of new feature articles analysing some of the smaller oil and gas companies from around the world, based on information supplied by *Online-Data*.* Here, we take a closer look at the activities of *Newfield Exploration*.**

Newfield Exploration Company is a Houston-based independent oil and gas exploration and production company. Its current focus areas include the Gulf of Mexico, along the US onshore Gulf Coast, in the Anadarko and Permian Basins, offshore north-western Australia, China's Bohai Bay and, more recently, the UK North Sea. Founded in 1989 and taken public in 1993, Newfield has become one of the Gulf of Mexico's most active drillers and ranks near the top in terms of daily gross operated production.

Total production from all Newfield's activities in 2002 reached 184.1bn cfe.

The company's growth strategy balances reserves acquisitions with drill bit opportunities. Its Board approved a 2003 capital budget of $450mn, an increase of 34% over 2002. Some 55–60% of 2003 expenditure will be invested in the Gulf of Mexico (including deepwater), 35–40% onshore US and the balance on international projects. Drilling plans include 25–35 wells in the Gulf of Mexico (including seven to 10 deep shelf wells and two to three deepwater wells), 45–50 wells onshore the Gulf Coast, 40–50 wells in the Mid-Continent, and one to three wells overseas.

Gulf of Mexico key

The Gulf of Mexico remains the largest focus area for the company, comprising nearly 45% of year-end proved reserves and just over half of Newfield's daily production. In 2003 the company expects to invest more than $200mn in the Gulf, representing the largest investment among the group's focus areas. It is a leader in the shallow waters of the Gulf, operating about 150 production platforms with gross daily production of more than 500mn cf.

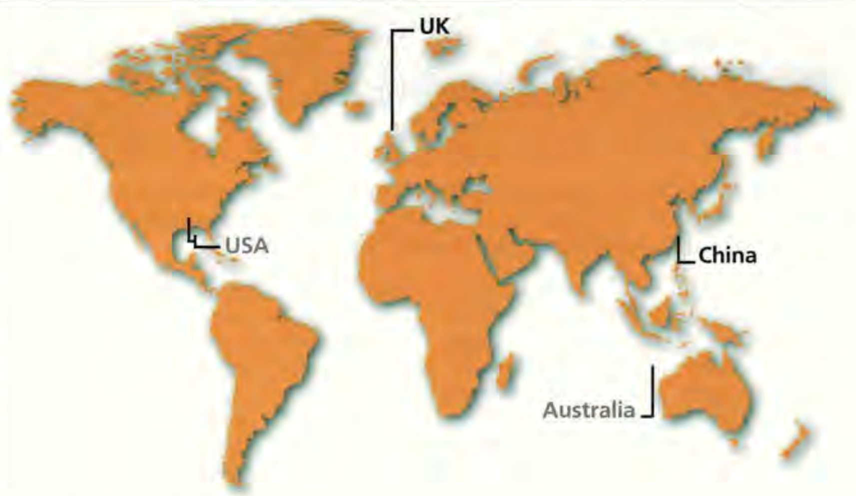
Although Newfield continues to work the traditional shelf plays, exploiting and developing prospects in and around existing fields, it is focusing an increasingly larger portion of its capital and resources to find higher potential targets at deeper drilling depths and in deeper water.

In May this year the company made a significant deep shelf discovery at West Cameron 73, located less than 10 miles offshore Louisiana in about 30 ft of water. The West Cameron 73 #1 well was drilled and evaluated with wireline logs to a total depth of 16,082 ft. The well encountered more than 250 ft of net gas pay in two zones below 15,000 ft. Newfield is currently evaluating development plans and expects first production from the field in early 2004. Under new rules proposed by the US Minerals Management Service (MMS), this discovery would qualify for royalty relief on the first 20bn cf of production.

Newfield acquired the West Cameron 73 block in a 2002 central Gulf of Mexico lease sale for $4.1mn. This discovery well is the first of seven to 10 deep shelf exploration wells planned in 2003. The company has drilled six successful deep shelf wells out of nine attempts to date. It operates the West Cameron 73 discovery with a 70% working interest. Westport Resources Corporation owns the remaining 30% interest.

Fastest growing area

As a percentage of total production, the onshore Gulf Coast has been Newfield's fastest growing area over the last two years – a trend that should continue in



Core operating areas:

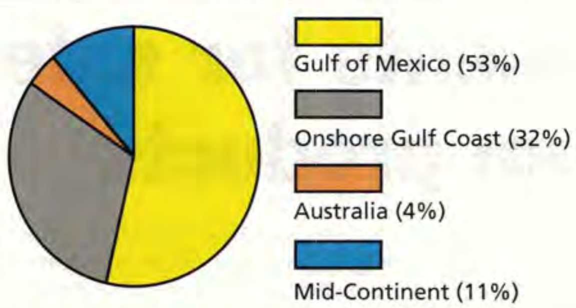
The outer continental shelf of the Gulf of Mexico, US

The onshore Gulf Coast of Texas and Louisiana, US

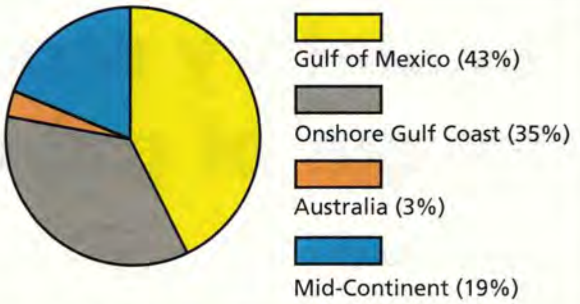
Oklahoma, US

The Timor Sea, offshore north-western Australia

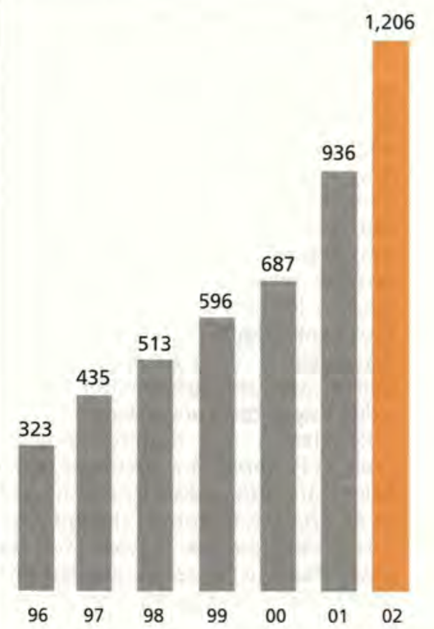
Areas of international activity



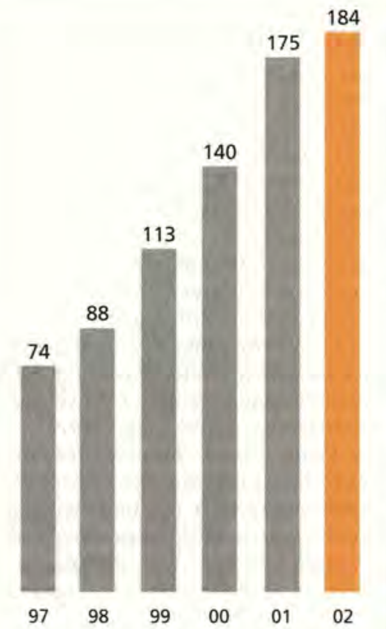
Distribution of production (635 mn cfe/d)



Distribution of reserves (1.3tn cfe)



Proved reserves (bn cfe)



Production (bn cfe)

2003. The company's acreage position and production volumes increased significantly in 2002 with the $640mn acquisition of EEX Corporation, which added 287.8bn cf of proved reserves to Newfield's portfolio and made it one of the largest independent producers in the prolific South Texas natural gas basin. Onshore Gulf Coast production is currently 190mn cf/d.

Most of the deepwater blocks acquired from EEX are operated in partnership with Shell. EEX had also recently entered into a joint venture with BP Exploration, which acquired 75% of EEX's interest in 23 outer continental shelf (OCS) leases. As part of this agreement, BP will conduct further leasing and geophysical activities in an area encompassing 140 OCS blocks.

Excluding the acquisition of EEX, Newfield added 181.2bn cfe of reserves with its core domestic programme during 2002, replacing 105% of production. Total domestic investment for the year was $308.8mn, including other acquisitions made primarily to capture drilling opportunities. US finding and development costs for 2002 were $1.70/mn cfe.

International operations

Newfield invested some $28mn in international operations in 2002, mainly in China and Australia where expenditures were related to appraisal of the 12-1 South field in Bohai Bay and the Montara field offshore Australia. Neither of these projects has yet been sanctioned for development and, accordingly, no reserves have been booked for these properties.

The company also has six exploration permits covering approximately 2.5mn acres (gross) in Australia's Timor Sea and owns and operates a 50% interest in two producing oil fields, Jabiru and Challis. The company is currently seeking a buyer for its stakes in Jabiru and Challis, which have a combined production rate of 8,000 b/d. The Challis field came onstream in 1989, Jabiru in 1990. The fields are operated by Gulf Australia Resources. Santos and ExxonMobil are also minor stakeholders in the fields.

In August last year D Roy Phillips joined the company as Managing Director, Newfield Petroleum UK. He will be responsible for the company's new initiative in the UK North Sea.

	2002	2001	% Change
United States			
Natural gas (bn cf)	144.7	133.2	9%
Oil and condensate (mn b)	5.2	5.5	(5%)
Australia			
Oil and condensate (mn b)	1.34	1.48	(9%)
Total production (bn cfe)	**184.1**	**175.2**	**5%**

Newfield exploration production

Visit Newfield Exploration's website at **www.newfld.com** or T: +1 281 847 6000, F: +1 281 847 6000.

*Online-Data specialises in web based publications for the oil industry, from the established 'Oil Company Key Facts' to the recently launched 'Gulf of Mexico Key Facts' and 'Oil Voice' sites.

Visit **www.oilvoice.com** to view over 300 continually updated oil company profiles. Alternatively, e:**cp@online-data.co.uk**

Regulatory requirements for safe storage of petroleum products

*Bruce Woodall,**

Chairman of Oil Tank Supplies and Storage Tank Services looks at some of the legislative requirements that those storing over 200 litres of oil and fuel on commercial premises or over 3,500 litres on domestic properties need to meet.

The oil and fuel storage sector is governed by a plethora of regulatory requirements to encourage safe storage (see box overleaf). One of the key requirements to be met by those holding oil and fuel in England are the Control of Pollution Oil Storage Regulations 2001; these require that any fuel/oil storage tank (bar the exemptions outlined in the box) capable of holding 200 litres or more to have secondary containment in the form of a drip tray or bund. The scope includes all tanks, drums, IBCs (intermediate bulk storage containers) or mobile bowsers.

Storage tank bunds, or catchpits, should be impermeable to petroleum products and water and be capable of holding 110% of the primary tank or, if more than one tank, 25% of the aggregate volume (whichever is the greater). The bund may be either a conventional constructed bund as shown in the Environment Agency's Pollution Prevention Guideline 2 or a proprietary prefabricated tank in bund (see **Figure 1**), which can be either open bunded or enclosed bunded. The advantage of the latter is that there is no ingress of rainwater and, therefore, there are no contaminated water disposal costs every few months as with open bunds. Furthermore, all bunds should have no drain openings or drain valves.

It is also important to note that Regulation 3(2)(b)-(c) of the Oil Storage Regulations requires the bund and tank to be positioned to minimise any risk of damage by impact. This means that in quarries, building sites or busy transport/warehousing yards storage tanks, especially plastic tanks, should be protected by a crash barrier or similar means if they are near moving plant.

Regulation 3(3) requires that every part of the oil storage installation is located within the bund, including valves, filters, sight gauges, vent pipes or other equipment ancillary to the tank. However, this is not required if the equipment is housed within a fill cabinet, which should have its own drip tray or be hard-plumbed to a kerbside pump or boiler. One suitable solution for new installations is an OTS Securitank (**Figure 1**), in which all the equipment is located within a cabinet that has a lockable roller shutter door and a drip tray to catch any spillage.

Regulation 3(1) requires that the product is stored in a container of sufficient strength and structural integrity to ensure that in normal circumstances it is unlikely to leak or burst. For new installations it is recommended that the tank has a design lifetime of a minimum of 20 years.

Staged implementation

The Oil Storage Regulations 2001 have a staged implementation – all new instal-

OTS Securitank

lations in England from March 2002 have had to comply with the requirements, while all existing 'significant risk' installations must comply from 1 September 2003 and all other existing installations from September 2005.

The deadline for the 'significant risk' installations is looming and many tanks still do not comply. There are no government statistics on commercial oil tanks, but it is estimated by OFTEC (Oil Firing Technical Association for the Petroleum Industry) that there are about 800,000 domestic tanks and possibly a further 400,000 commercial tanks yet to meet the legislative requirements.

It should be noted that unlike most other corporate legislation, Regulation 7 of the Control of Pollution (Oil Storage) Regulations 2001 states that the 'responsible person' is the person who has custody or control of the product and (s)he is required to ensure regulatory compliance. Companies storing petroleum products therefore need competent personnel to manage their installations and, where necessary, commission suitable plant modifications, inspections and maintenance.

Avoiding risk

So, how do you avoid the risk of non-compliance? The first thing to do is to have a comprehensive survey carried out of all fuel or oils stored on the premises. This should include a risk assessment of 'significant risks'. The survey should be carried out by a competent person who should carry professional indemnity insurance. Their survey report should cover all aspects of the installation, including bunding, ancillary equipment, oil spill control and service and maintenance records.

The report should prioritise any necessary remedial works required and the 'significant risk' items should be rectified immediately by a competent person, preferably holding an OFTEC OFT/ 600A certificate. A plan should then be drawn up to bring all the other installations into regulatory compliance by the cut-off date of September 2005.

Safe installations

There are three other points that are vital to a safe installation. Firstly, however good the installation it needs a proper maintenance and service schedule to keep it up to standard. Secondly, the responsible person needs adequate training in receiving petroleum products, knowledge of the ancillary equipment and the use of oil spill materials. Lastly, it should be noted that the oil distribution industry may not deliver to any tanks that do not conform to the regulations as, if a pollution incident occurred, they may be also held liable.

**Bruce Woodall is Chairman of Oil Tank Supplies and Storage Tank Services and has been involved in the oil tank and services industry for nearly 40 years. He is a Member of the Energy Institute (EI); an Executive Member of OFTEC and sits on the BSI. He has been involved in carrying out professional indemnity surveys of tanks and tank farms for many years.*

Regulatory requirements

Those storing fuel and/or oil on their business premises in the UK must meet a plethora of regulatory requirements, including:

- The Control of Pollution Oil Storage Regulations 2001 for England, which are made under sections 92 and 219 of the Water Resources Act 1991. These exclude refining and distribution of oils, agricultural fuel stores (see next point), and fuels kept in buildings (although no definition is given of a building), road and rail tankers and single domestic premises with tanks under 3,500 litres. These regulations are shortly to be followed by similar arrangements in Scotland and Wales.
- The Control of Pollution (Silage, Slurry and Agricultural Fuel Oil) Regulations 1991, amended 1997 – gives minimum standards for agricultural fuel stores.
- Water Resources Act 1991 (WRA) – require consent for discharges to controlled waters. S.85 makes it an offence to cause or knowingly permit poisonous, noxious or polluting matter to enter controlled waters, or to breach conditions of discharge consent.
- Anti-Pollution Works Regulations 1999 – the Environment Agency (EA) can serve works notices on polluters or potential polluters requiring them to carry out works. Under s161 WRA the EA can carry out work itself and recover costs.
- Groundwater Regulations 1988 (also applicable in Scotland) – control disposal to land that could contaminate groundwater. The EA can serve notice under reg. 19 prohibiting activity that may result in indirect discharge to groundwater. At present underground storage tanks are covered by these regulations.
- Part IIA (2A) of the Environment Protection Act (EPA) 1990 – liability for clean-up of contaminated land and water.
- Waste Management Licensing Regulations 1994 – require a waste management licence (WML) to store waste oil. This can include conditions for storage and disposal. It is an offence under s33 EPA 1990 to breach conditions of WML.
- Pollution Prevention and Control Regulations 2001 – PPC permit conditions could cover storage and disposal of oil.
- COMAH (Control of Major Accidents and Hazards Regulations) 1999 – covers major accidents at larger installations that have safety consequences, environmental consequences, or both.

...continued from p16

the Technical European Tank Storage Platform (TETSP), which comprises a number of trade associations including the Federation of European Tank Storage Associations (FETSA), the European Chemical Industry Council (CEFIC), the Federation of European Chemical Distrbutors (FECC) and the Oil Companies' European Organisation for Environment, Health and Safety (CONCAWE). The work was expected to take no more than two years but, four years on, is still not complete.

In fact, most independent storage terminals – other than those that incorporate process facilities or handle some specific chemicals with a notable environmental impact – will fall outside the scope of IPPC. However, terminal operators believe that regulators and enforcement agencies will apply the BREF to them in any case, as there is no other similar guidance, and are therefore keen to be involved. A risk-based strategy has been employed in drawing up the data sets, which indicates that terminal operators will have to look closely at the BREF once it appears, since the best available technique for pollution prevention is site-specific, if not tank-specific.

The final draft of the Storage BREF is expected to be agreed around the middle of next year, after which terminal operators will need to assign yet more management time to investigating how their facilities match up to its specifications and – possibly – yet more money on replacing or installing equipment. Their customers may have to be aware of this when it comes to renegotiating storage leases.

ATEX approved EExd connectors

Hazardous area specialist Hawke International is soon to launch its new ATEX approved EExd connector range.

The stainless steel bodied connector is reported to be the 'ideal' coupler for Zone 1 and 2 explosive environments. ATEX compliant, the new design retains many of the best features of the manufacturer's previous connector range, with additional innovations based on user feedback.

The connectors are tested and certified for a safe operating temperature range of –40°C to +100°C. The standard temperature classification of T6 at 40°C ambient temperature is supplemented by optional higher ambient temperatures and T5 classification.

All models have deluge and ingress protection to IP66/67. The connectors are available in many sizes and configurations, varying from M16 to M63 mm and feature from three to 60 pins.

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e: sales@ehawke.com
www.ehawke.com

New colour lab

Tintometer has established The Colour Laboratory, a specialised colour analysis service that is available on a test-by-test basis or as an outsource facility to companies around the world. The service is suitable for a broad range of sample types, including mineral and industrial oils and fuels, chemicals and petrochemicals, waters and effluents.

Measurements are carried out to all relevant international and other trade standards and specifications, including ASTM methods. Tintometer has been awarded UK Accreditation Service (ACAS) accreditation as a calibration laboratory for spectral response and CIE measurements.

T: +44 (0)1722 327242
e: **sales@tintometer.com**

World's first ever rolling-swing valve unveiled

Cambridge, UK-based Camcon Technology, developer of the Camcon® binary actuator, recently launched what it claims is the world's first rolling-swing valve which is 'set to revolutionise the fluid control industries'.

Based on the principles of Camcon's binary actuating technology, the new valve has been specifically developed for applications in the unfiltered fluids environment, in which its hardened roller attachment can be used to crush small solid particles. The unit utilises a catapult-like technology based on high power permanent magnets and a spring-loaded armature. A very short electrical pulse (approximately 2 milliseconds) disrupts the magnetic field and causes the sprung armature to switch from one position to another, thereby opening or closing the valve. During changeover action the whole armature rolls from one stable position to the opposite position. No power is required to hold the valve in either an open or closed position.

The manufacturer claims that the high-speed, low energy consumption, low heat dissipation and long life characteristics of the Camcon binary actuator mean that it has applications in a whole new range of areas, as well as being a replacement for existing actuator and valve technologies. Applications include the automotive industry (internal combustion engines), aviation (noise and pollution reduction), control of accurate gas and liquid flow control systems, and oil drilling and production (remote location on land and subsea).

The rolling-swing valve characteristics include a fast reaction time of just three milliseconds; low energy – less than one joule per change over, zero current consumption while in either of its two stable positions; bi-directional flow permitted; high pressure capability; large orifice size; and suitability for unfiltered fluids.

T: +44 (0)1223 873650
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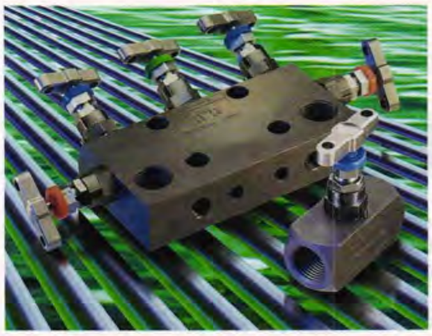
www.camcontec.com

Exotic alloys boost processing protection



Parker Instrumentation has extended the versatility of its high-integrity manifold range with new exotic alloy versions to assure corrosion-free performance in a wider range of fluid instrumentation applications.

Now available in materials including Titanium, Monel, 6Mo, Hastelloy, Inconel, Incolloy and Super Duplex, as well as standard stainless steel, the manifolds allow users to optimise protection against the aggressive media found in chemical, oil, gas and other processes.

Typical applications include oil and gas instrumentation systems exposed to sour gas or salt spray, and in chemical and pharmaceutical plants to withstand the effects of media such as acids, ethanol and halides.

T: +44 (0)1271 313131
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www.parker.com

High and medium voltage motors

WEG Electric Motors has launched its 'H' and 'M' Line ranges of medium and high voltage motors for use in hazardous and technically challenging oil and gas applications, both on and offshore. Designed in conjunction with the oil industry, the new motors are claimed to 'deliver outstanding performance, reliability and safety in the most arduous operating environments worldwide'.

The H- and M-Line motors have a wide operating range, up to 20 MW, and are reported to meet all hazardous area classifications in accordance with the latest ATEX directives.

The M-Line range is suited to applications such as water injection, multi-stage gas compression and oil pipeline duties. Designed for larger applications in the output range up to 20 MW the M-Line range utilises a box frame construction suited to Ex p and pre-start purged Ex n applications for Zone 1 and Zone 2 areas having low leakage rates. The internal dispersement pipes within the box frame ensure an efficient and quick purge cycle, states the manufacturer, thus keeping the cost of providing purging air/inert gas to a minimum while ensuring quick start-up times for operators.

For smaller applications the H-Line range offers robustness of construction and is available in safe area, Ex n and Ex e designs. The H-Line motors cater for medium voltage applications in the range up to 3.15 MW and voltages up to 6,600 V (50 Hz or 60 Hz). Manufactured in IEC frame sizes from 315 to 630 they are said to be compact and reliable machines with sturdy cast-iron frames and high levels of resistance to corrosion.

T: + 44(0)1527 596748
e: wegsales@wegelectricmotors.co.uk
www.weg.com.br

Cable-bundling in the North Sea

Panduit is to supply its new stainless steel cable ties to Norsk Hydro's Njørd B oil storage vessel in the Norwegian sector of the North Sea.

The stainless steel cable ties hold cable bundles on cable trays securely, without becoming loose through vibration – a common predicament onboard vessels in rough sea, states the company. The ties are of a new ball-locking design and are engineered for the most extreme of applications.

Claimed to offer the market's strongest loop tensile of up to 2,000 Newton, the cable ties are said to assure locking in any position or condition. At the same time they are reported to demonstrate all the advantages of the original design – a unique locking ramp that provides higher retained tension for a more secure bundle, self-locking with low thread force for fast installation and fully rounded edges for an extra margin of safety.

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

Membership News

NEW MEMBERS

Mr P K Adegunle, Total Nigeria plc
Mr P Bhundia, East African Gas Company Ltd
Mr P Botschek, CEFIC
Mr P J Burgess, Crewe
Mr R M A Clarke, Brough
Mr S Cochrane, Park Brown International
Mr D R Connell, Edinburgh
Mr F de Souza Aranha Cascione, Brazil
Mr A J Evans, Reservoir Management Ltd
Mr J Fewtrell, GEL Group Ltd
Ms F Fraulo, Fitch Ratings Ltd
Mr M Greenhill-Hooper, Borax Europe Ltd
Mr J Hamilton, ABN AMRO
Mr R Hawkins, Merthyr Tydfil
Mr A Holmes, Mechanica/OTS
Mr Z Ikodinovic, NIS – Petroleum Industry of Serbia
Mr J Ikuvbogie, c/o Otomiewo & Company
Mr S G Katsimpiris, Greece
Mr N Lemonidis, Greece
Mr R Lewis, GEL Group Ltd
Mr I S Manson, Norman Broadbent
Mr M Moroney, John Brown Hydrocarbons Ltd
Mr A O Olumese, Amalgamated Direct Services (Nig) Ltd
Mr S O A Omidiji, City Express Bank Ltd
Mr N J Pickwell, Aberdeen
Mr M K Pirie, Plymouth
Mr I J Pocock, Thales Missile Electronics Ltd
Mr E Ritchie, Flow Ltd
Mr B Roberts, Inspection Services
Mr T Roberts, London
Mr S D Robertson, Douglas Westwood Ltd
Mr B Robinson, British Sugar
Mr G Rodger, ChevronTexaco UK Ltd
Mr M Smadi, Cardiff
Mr P A Smedley, Teddington
Mrs B Tvedt, Statoil (UK) Ltd
Mr V Van Hasselt, IVC Consulting
Mr D Vukcevic, NIS – Petroleum Industry of Serbia
Mr K T Wee, Brunei Shell Petroleum
Mr P Wemyss, Petersfield
Mr R M Westwood, Douglas Westwood Ltd
Mr K S Woods, Texoil Ltd

STUDENTS

Mr B M Abdullahi, Aberdeen
Mr J M Clancy, Stonehaven
Mr B Garba, Aberdeen
Ms S Idowu, Dundee
Mr P D Kellett, London
Mr B Malkano, Aberdeen
Mr T M Stewart, Midlothian
Mr A Tejuoso, London

STUDENT PRIZEWINNER

Mr J S Watkin, Aberdeen

DEATHS

We have been notified of the death of the following member:
Mr S V Paros FInstPet
Date of Birth: 1/6/1928
Joined IP: 1/10/1967

IP Certificates

Bob Hooks, Chairman of the Stanlow Branch, presents Denise Penny of Shell Global Solutions with the IP's Certificate of Appreciation for her work at the IP in the field of elemental analysis.

Branch News

ESSEX BRANCH

Dancing the night away

The Institute of Petroleum's Essex Branch held its Annual Dinner/Dance in March 2003. Over 300 people attended, including IP Director General Louise Kingham.

After tripping the light fantastic, Louise took the opportunity to present IP Certificates and ties to Steve Goldsmith, Director of IMS and D; Jason Hornsby, Commercial Manager of Vopak Terminals; and Stuart Fryer, South East Business Manager, SGS Oil, Gas and Chemical Services.

The Essex Branch Annual Dinner/Dance has always been well attended. However, this year sadly marked the last time it would be held at the Heybridge Hotel in Ingatestone – the venue for the past seven years – which has now been sold for redevelopment.

STOP PRESS – STOP PRESS

The new Energy Institute website will be launched in September. See *Petroleum Review's* September e-world column for more information on the benefits available to EI members. The new EI web address is **www.energyinst.org.uk** Please note all EI staff email addresses end with **@energyinst.org.uk**

NEW Publications

Oil in the Sea III: Inputs, Fates and Effects*

(The National Academies Press, PO Box 317, Oxford OX2 9RU, UK. T: +44 (0)1865 865466; F: +44 (0)1865 862763; www.nap.edu*). ISBN 0 309 08438 5. 270 pages. £39.95 (hardback).*

This publication provides an estimate of oil pollutant discharge into marine waters, including an evaluation of the methods for assessing petroleum load and a discussion about the concern these loads represent. Featuring studies of the *Exxon Valdez* spill and other notable events, the book identifies important research questions and makes recommendations for the better analysis of, and more effective measures against, pollutant discharge. The book will be of use to energy policy makers, industry officials and managers, engineers and researchers, and advocates for the marine environment.

Performance of European Cross-Country Oil Pipelines*

(Concawe, Boulevard du Souverain 165, B-1160 Brussels, Belgium. T: +32 2 566 91 60; F: +32 2 566 91 81; e: info@concawe.be*). 23 pages. Free download from* www.concawe.be

This report details the performance in 2001 of 35,545 km of onshore oil pipelines in Europe with regards to hydrocarbon spillage. Incidents are analysed by cause and the effectiveness of the clean-up operations is recorded. The inventory of European oil pipelines covered by this annual publication has been increased by 4,800 km with the inclusion of data for the Czech Republic, Hungary and Slovakia. Direct repair and clean-up costs are reported. Performance in 2001 is shown to have once again been better than the long-term average, with third-party activities remaining the main cause of spillage incidents. The report also gives the annual intelligence pig inspection statistics.

Handbook of Electrical Engineering for Practitioners in the Oil, Gas and Petrochemical Industry

Alan L Sheldrake (John Wiley & Sons, The Atrium, Southern Gate, Chichester PO19 8SQ, UK. T: +44 (0)1243 770668; F: +44 (0)1243 770638). ISBN 0 471 49631 6. 750 pages. Price: £120 (hardback).

Developed from a series of lectures on electrical power systems given to oil company staff and university students, this handbook provides a practical guide to power system design specifically for the oil, gas and petrochemical sectors. It discusses the necessary theories behind the design of facilities and offers practical guidance on selecting the power systems and equipment used on offshore production platforms, drilling rigs, pipelines and chemical plants.

European Downstream Oil Industry Safety Performance*

(Concawe, Boulevard du Souverain 165, B-1160 Brussels, Belgium. T: +32 2 566 91 60; F: +32 2 566 91 81; e: info@concawe.be*). 16 pages. Free download from* www.concawe.be

This report on safety performance in the European downstream oil industry analyses both company employee and contractor data for the year 2001 from 19 companies, representing some 90% of Europe's refining capacity. Primarily covering the EU, European Economic Area and Hungary, the data is reported in terms of Lost Workday Injury Frequency (LWIF), as well as a range of other metrics, and compared with averages for the previous five-year period (1996–2000) and to similar statistics from related industries and general EU figures. The LWIF for 2001 was 4.3, slightly lower than the 4.5 average for the previous five-year period.

** Held in IP Library*

Latest from the Library

YOUR OFFICE AWAY FROM HOME

The new Energy Institute Library & Information Service (LIS)

LIS will continue to provide a full library and information service – including desk and online research, statistics service, loans to members and free Internet access for visitors – under the auspices of the new Energy Institute.

Members of the Energy Institute will still have free entry to the library and the extensive research resources available. The major change will be the extension of the subjects covered. Any suggestions for relevant material that you would like to see in the library can be sent for consideration to Catherine Cosgrove (see below for contact details).

New Editions to Library Stock

- *20th International North Sea Flow Measurement Workshop: Held 22–25 October 2002, St Andrews Bay Resort, Scotland. (Includes CD-ROM).* National Engineering Laboratory (NEL); Norwegian Society of Chartered Engineers; Norwegian Society for Oil & Gas Measurement; Institute of Petroleum, London, 2002. ISBN 0 85293 332 0.
- *An Emerging Market for the Environment: A Guide to Emissions Trading.* First Edition. UNCTAD, Denmark, 2002. ISBN 8755031501.
- *European Electricity Review 2003: A Power in Europe/Energy in East Europe Special Edition.* Henry Edwardes-Evans and Martin Burdett (Eds). Platts, Wimbledon, UK, 2003.
- *Flexibility in Natural Gas Supply and Demand.* International Energy Agency (IEA), Paris, France, 2002. ISBN 9264199381.
- *Fundamentals of Gas to Liquids: A Comprehensive Guide to the GTL Industry.* Petroleum Economist; Sasol Chevron. Petroleum Economist, London, UK, 2003. ISBN 1861861583.
- *Renewable Energy Sources Statistics in the EU, Iceland and Norway: Data 1989–2000.* Eurostat, Luxembourg, 2002. ISBN 9289442514.
- *Unloading Petrol from Road Tankers: Dangerous Substances and Explosive Atmospheres Regulations 2002: Approved Code of Practice and Guidance.* First Edition. Health & Safety Executive (HSE), Norwich, UK, 2003. ISBN 0717621979.

Contact Details

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

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

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Who Should Attend?

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For more information, see enclosed inserts or contact Nick Wilkinson at IP Training or visit: www.petroleum.co.uk/training

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