Petroleum review

FEBRUARY 2003

Russia

- Expanding oil production targets export markets

Canada

- Next-generation oil sands project

E&P

- New technology to cut subsea costs

Fabrication

- European fabricators face challenging future

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IP Certification – Petroleum Inspector Proficiency Programme

The International Federation of Inspection Agencies (IFIA) and The Institute of Petroleum (IP) are pleased to announce the UK launch of the Petroleum Inspector Certification Programme.

The Petroleum Inspector Certification Programme has been running successfully in the US for four years and has recently been extended to Latin America. Introduction to the UK is the first step towards its implementation throughout Europe and a full worldwide programme is envisaged.

The aim of the programme is to ensure a consistent level of proficiency for Petroleum Inspectors via an examination and by confirmation of experience as defined in the IFIA Inspector Training Record Book. The IP will provide independent monitoring and marking of the examinations and will verify the Inspectors' training records.

There will be minor regional differences in the examination and training requirements but the qualification 'Certified Inspector of Petroleum' will be recognised as an international qualification.

All eligible

Although the programme will be administered by IFIA it will not be restricted to IFIA members only. All Petroleum Inspectors will be eligible for certification providing they have a minimum of six months' experience, have obtained the specified training and pass the examination. Certificates will be issued by the IP and will be valid for a period of five years after which Inspectors must retake the examination.

A Technical Advisory Board consisting of representatives from IFIA, oil companies and the IP will monitor the programme content.

Test questions

The examination will comprise 100 questions selected at random from a question book containing over 400 questions. Copies of the full set of test questions can be obtained from IFIA and order forms for these and for the Training Record Books can be found on the IFIA website – www.ifia-federation.org – which also carries full details of the programme.

The first examinations will be held this summer at the IP in London, with further examinations to be held at regional centres. A timetable will be published in April and this, together with booking forms, will also be available at the above web address.

Costs* for 2003 will be as follows:

Item	IFIA Member	Non-IFIA Member
Examination – London	£45	£150
Examination – Other	£65	£220
Test Question Book	£5	£15
Training Record Book	£2	£5

*The above costs do not include VAT.

IFIA

International Federation of Inspection Agencies Petroleum and Petrochemical Committee

For more information please visit the IFIA website at

www.ifia-federation.org

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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: Main pic – Pipeline network at one of the two current production pads at Petro-Canada's MacKay River oil sands project in Canada ***Photo: Petro-Canada***

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ROUNDUP

From the Editor

Oil at $20/b or $100/b in 2003?

With the drums of war beating ever louder, Brent prices above $30 and no end in sight for the Venezuelan general strike, oil production capacity is now the key concern.

The International Energy Agency (IEA) in its latest monthly oil report suggests that Opec, even excluding Venezuela and Iraq, still had an estimated spare capacity of around 3mn b/d versus December production. However, analysts are now saying that if there is any spare capacity at all it is in Saudi Arabia and maybe the UAE (Abu Dhabi).

The main problems with theoretical calculations of capacity is they assume everything is operating normally. In the now very elderly fields of the Middle East this is a heroic, not to say unrealistic, assumption.

Tabulated below is December's Opec production, the IEA's estimate of sustainable capacity, the highest volumes produced in the last two years (a sort of proven capacity) and 2001 consumption by country. This shows that Indonesia is now unlikely to be a net exporter of crude at all. It is not quite clear how a country can be an Opec member if it exports little oil.

The only imminent new capacity in Opec countries is the start-up of Anadarko's Ourhoud field in Algeria and the build-up in production from ExxonMobil's Yoho field in Nigeria.

It is likely most, if not all, Opec producers have now expanded production to capacity. If Saudi produces 9mn b/d in February, as it has indicated, it too would be close to capacity.

Venezuela is currently the wildest card in the pack. Rapid shut-ins and sabotage are reported to have reduced capacity to 2.35mn b/d, excluding Orinoco production. However, the return of full Venezuelan production would flip the world from rising prices to falling prices in one.

The other major uncertainty is Iraqi production. It produced 2.3mn b/d in December. In early January it reduced exports by 0.5mn b/d. Would a war lead to the cut off of Iraqi production? Would the oil fields be fired? And for how long would supply be interrupted? These are the questions everyone wants answered and to which there are no answers.

The IEA currently estimates non-Opec production will rise to 49.4mn b/d in 2003, an increase of 1.4mn b/d on 2002. The largest gains are from Russia (500,000 b/d); Kazakhstan and Azerbaijan (200,000 b/d); Canada (150,000 b/d); Mexico, US, Africa and Brazil (100,000 b/d each). These additional volumes would undoubtedly undermine oil prices but only if Opec produces fairly normally and demand growth remains subdued. War and disaster scenarios produce oil price projections all the way to Sheikh Yamani's rather alarming $80–$100/b prediction.

In last month's tabulation of the mega projects some data was omitted and more information has come in. Anadarko's Ourhoud field in the Berkine Basin of Algeria should start up soon and reach 230,000 b/d by mid-year while full development of Ourhoud and other block 404 fields should reach 600,000 b/d by 2006. ExxonMobil's Grane field in the Norwegian sector is also a 2003 start-up, with peak flows of 200,000 b/d. Ocean Energy has a 23.75% holding in the Zafiro South project. For Karachaganak peak flows on the completion of Phase 2 at the end of 2003 are 158,000 b/d (oil) and 588mn cf/d (gas). In place reserves are 10bn barrels (oil) and 48tn cf (gas), and the shareholders are Eni and BG (joint operators, 32.5% each), ChevronTexaco (20%) and Lukoil (15%).

Petroleum Review is always pleased to receive information to make our databases more accurate and comprehensive. Many thanks to all who have provided us with data/corrections.

Congratulations

Congratulations go to John Wildman who answered the most questions correctly in our annual Christmas quiz, and to the runner-up Tim Hill. If you would like to know the answers visit the IP website at **www.petroleum.co.uk**

Chris Skrebowski

Country	Production Dec 2002	Production Highest last 2 years	Capacity IEA	Consumption 2001
Algeria	0.98	0.98	1.10	0.20
Indonesia	1.19	1.30	1.19	1.09
Iran	3.60	3.85	3.90	1.13
Kuwait	1.91	2.22	2.15	0.21
Libya	1.34	1.45	1.45	0.05?
Nigeria	2.04	2.18	2.25	0.5?
Qatar	0.72	0.74	0.75	0.03
Saudi Arabia	8.02	8.85	9.50	1.35
UAE	2.01	2.35	2.50	0.28
Venezuela	0.71	3.00	2.35	0.49
Iraq	2.32	3.03	2.80	0.6?

Opec capacity and consumption (mn b/d)

eworld

The UK Health and Safety Executive (HSE) has published its latest statistics on workplace safety, work-related ill health and enforcement action in Great Britain. *Health and Safety Statistics Highlights 2001/2002* presents the top level statistics, while more detailed data and commentary are available on the HSE website at **www.hse.gov.uk/statistics** The *Highlights* document itself can be viewed at **www.hse.gov.uk/statistics/overpic.htm**

Pilot, the joint government/industry initiative to improve competitiveness in the UK offshore oil and gas industry, has relaunched its website at **www.pilottaskforce.co.uk**

IHS Energy (**www.ihsenergy.com**) has launched a new oil production and forecasting service that will be available on a monthly updated basis. The 'Global Oil Production & Forecasting Report' will provide essential production data, development, forecasts and commentary on all countries producing more than 50,000 b/d of oil. It will be available online through the company's Global E&P Information (GEPS) portal.

Shell International Trading and Shipping Company (STASCo) and Sembawang Shipyard have unveiled a new e-collaboration portal that can be viewed at **www.semballiance.com** – designed to facilitate ship refits between the two companies.

Ofgem's draft proposals for the Regulation of Independent Gas Transporter Charging in the UK can be found on the publications section of its website at **www.ofgem.gov.uk**

ChevronTexaco recently unveiled the company's new online ChevronTexaco Opera Information Center that can be viewed at **www.operainfo.org** (or from **www.chevrontexaco.com**) that is designed to make in-depth information about opera available to the general public and opera aficionados alike.

In Brief

UK

PGS Data Processing is to rent super- *computing capacity on demand from IBM.**

BG, BP and Amerada Hess have pro- *duced first gas from the southern North Sea Juno project's Whittle, Wollaston and Minerva fields in the second phase of the Easington Catchment Area (ECA) development.**

BG Group is disposing of its 60% *equity in the southern North Sea block 47/15 that contains the Rose gas discovery to Centrica Resources who will also assume the operatorship.**

An Amerada Hess-led consortium is *reported to have discovered oil and gas just 25 km from the Faeroese sector of the UK Continental Shelf.*

Europe

The Norwegian Government has *approved Norsk Hydro's NKr2.7bn development plan for the North Sea Vigdis Extension project that will produce 45,000 b/d of oil.**

Production has commenced from the *two ExxonMobil-operated Sigyn satellites in the North Sea some three months ahead of schedule reports Statoil.**

North America

TrueNorth Energy has shelved its *$3.5bn Fort Hills oil sands project in Canada, stating that its search for a new partner had not been successful.**

Complete news update

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

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

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

www.petroleum.co.uk

NEWS Upstream

Murdoch K produces first gas

Conoco (UK) (59.4%) and co-venturers Tullow Oil (14.1%) and GDF Britain (26.4%) have commenced first gas production from the Murdoch K field in the southern sector of the UK North Sea. The field flowed some 204mn cf/d of gas on test. It is the second Carboniferous field to be produced as part of the CMS III subsea-based development that is estimated to hold some 430bn cf of gas. The four other fields in the CMS III project are Hawksley, McAdam, Boulton H and Watt. Hawksley came onstream in September 2002 at a sustained rate of 170mn cf/d.

The third development well is currently being drilled on the McAdam field. First production is expected in 1Q2003.

A new compression module is to be installed in mid-2003, which will double the CMS compression capacity for existing and new production, and will provide for future gas developments in the area.

African and Middle East upstream developments

Stella Zenkovich reports on recent E&P developments in the Middle East and Africa:

- An agreement on Saudi Arabia's Natural Gas Initiative, involving a minimum $25bn of investment, is to be reached shortly with foreign oil companies, according to Jeroen ven der Veer, President of Royal Petroleum and Vice President of Shell. Three consortia are involved in negotiations with Riyadh, Shell heading one of them.
- Oil and gas exploration is to commence in Pakistan's Baluchistan Province, Petroleum Secretary Abdullah Yousaf has announced from Islamabad. Some 25 companies – four indigenious – are involved in oil and gas exploration in the country.
- Mol Pakistan Oil & Gas, an operating partner holding a 10% stake in a consortium with local companies POL, PPL and OGDLC, has reported 'promising' test results for a gas find in block 3370-3 in Pakistan's Thail Black region.
- Gas reserves in the Middle East have reached 800tn cf, equivalent to 16% of the world's total gas reserves, according to Dr Shaikh Mohammed, Director General of Banagas and Chairman of GPA-GCC in Bahrain.
- New deep and ultra-deep offshore oil strikes have been announced by Angola's Oil Minister Desiderio Costa on blocks 14, 15, 17 and 31 of the Low Congo Basin. It has also been announced that a joint study between Sonangol and Shell is to lead to the division of blocks of the west ultra-deep fields of the basin.
- Nigerian Agip Exploration, a subsidiary of Italy's Agip, is planning to become Nigeria's first deep offshore oil producer with initial production expected in March 2003 from the OPL 211 and 216 blocks that it operates under a PSA with Shell Nigeria.

Roncador back in production

Petrobras restarted production at the Roncador field on 8 December 2002, bringing onstream a new production platform, the *FPSO Brasil*. The platform is to be connected to 11 wells, eight of which will produce oil – the remaining wells are water injectors. Five of the production wells were previously connected to P-36. The first well came onstream at 22,000 b/d. The second well will boost production to 40,000 b/d and 700,000 cm/d of gas. Production is expected to peak at 90,000 b/d in 2H2003. Field reserves are put at 2bn boe.

Field production at Roncador was stopped in March 2001 following an accident on the P-36 platform. The *FPSO Brasil* has been leased until 2007 at which point all field wells will be reoriented to platform P-52, which is currently undergoing a bidding phase. The *FPSO Brasil* can store 1.7mn barrels of oil, process 90,000 b/d of oil, compress 3mn cm/d of gas and inject 15,000 cm/d of water.

Tuscan Energy secures Ardmore funding

Tuscan Energy has secured funding from private equity investors Aberdeen Murray Johnstone Private Equity (AMJPE) and US bank TCW to carry out its development of the Ardmore field in the central North Sea. The combination of new debt and equity funding will bring the total investment in Tuscan Energy to £35mn, of which AMJPE client funds invested £10mn.

Up to four high-angle production wells are to be drilled on Ardmore, previously known as Argyll – the first North Sea field to produce oil. It is planned to recover 20–25mn barrels of oil over a two-year period, with first oil expected in late 2003.

Paladin adds to North Sea portfolio

Paladin Resources is planning the $153mn acquisition from BP and Amerada Hess of a portfolio of producing interests in the North Sea Arbroath, Montrose and Arkwright fields and surrounding acreage including the Carnoustie and Wood discoveries. Proven and probable reserves in the assets are put at 39.5mn boe.

The company has entered an alliance with Petrofac and the Helix RDS consultancy to operate the fields. On completion of the deal Petrofac will act as duty holder on the platforms on behalf of Paladin – claimed to be the first time a facilities management company has taken on this role for fixed platforms in the North Sea. Helix RDS will provide reservoir and well management services.

Paladin has also proposed a placing and open share offer to raise $42mn.

LNG expansion

Marathon Oil has awarded a front-end engineering and design (FEED) contract to Bechtel for the planned Phase 3 expansion project in Equatorial Guinea. The expansion involves the construction of a LNG plant and related facilities that will enable Marathon and partners to further commercialise the substantial gas reserves in the Alba field.

The target date for the first LNG cargo from the Phase 3 expansion project is 2006/2007.

Phase 3 will complement the Phase 2A and 2B expansion projects that will increase total condensate production capacity to 54,000 b/d, and LPG capacity to more than 16,000 b/d, respectively. Phase 2A is expected to complete by 4Q2003, with Phase 2B slated to complete in October 2004.

Penguins onstream

Shell Expro produced first oil from the Penguin field in North Sea blocks 211/13a and 211/14 last month, some six months earlier than the date proposed in the field development plan on which the project was sanctioned. Oil is being transported via the Brent system to the Sullom Voe terminal. Primary and associated gas is also being produced via the FLAGS pipeline to the Shell/Esso gas terminal at St Fergus.

The Penguins field cluster is expected to produce 50mn barrels of oil and 175bn cf of gas over a nine-year field life. Production is forecast to peak at 40,000 b/d of oil and 70mn cf/d of gas. The project's subsea completions are tied-back via a single 16-inch diameter production pipeline to the Brent Charlie platform, which at 65 km is the longest North Sea subsea tie-back to date.

Enhanced oil recovery first in Canada

Talisman Energy has commenced a nitrogen injection pilot project at the Turner Valley oil field in Alberta, reportedly the first enhanced oil recovery (EOR) project of its kind in Canada. A three-year evaluation period is planned to demonstrate that nitrogen gas can be injected into mature oil fields to increase recovery of oil and natural gas liquids. A successful pilot project would be expanded and lead to full-scale development, states the company.

The Turner Valley oil field contains an estimated 1bn barrels of oil in place, of which only 15% has been recovered to date. The field came onstream over 65 years ago and has been under waterflood for over 40 years.

The EOR project utilises a membrane technology to extract nitrogen from air, which the company claims could offer a cost-effective alternative to the cryogenic technology used elsewhere. Capital cost efficiencies may be achieved through the use of suspended wellbores as injectors and integration with existing equipment. The project is also eligible for a 5% flat Experimental Project Petroleum Royalty on the Crown's share of oil production, representing approximately 80% of the total royalty volume, reports Talisman.

'An incremental 3–10% from the nitrogen flood has the potential to increase oil recovery by 30–100mn barrels and extend the remaining life of the field beyond 20 years,' President and CEO Jim Buckee stated.

In Brief

Apache Corporation has paid $260mn *to a private company for a number of South Louisiana properties. The acquisition adds more than 10% to Apache's US natural gas production.*

Talisman Energy has announced its *largest ever exploration programme in the company's 10-year history. A record $660mn has been approved for exploration projects in 2003.**

Shell Canada and Western Oil Sands *are reported to have commenced production of bitumen from the Muskeg River Mine located 75 km north of Fort McMurray in Canada. The Athabasca Oil Sands project is expected to produce 155,000 b/d of bitumen in 2003 and will supply 10% of Canada's oil needs.**

TotalFinaElf is to acquire a 43.5% stake *in the Surmont exploration permit in Athabasca, Alberta, part of an ongoing heavy oil sands thermal extraction pilot project that started in 1998. The project partners are ConocoPhillips (operator, 43.5%) and Devon (13%). Full scale development is due onstream in 2007.*

The Board of ConocoPhillips has *approved a $6.6bn capital budget for 2003. Some 73%, $4.4bn, of the 2003 budget will go on E&P activities.**

Middle East

Soyuzneftegaz of Russia is reported *to have signed an agreement with the Iraqi authorities under which it will develop four blocks in Iraq's western desert as well as the Rafidain field in the south of the country.*

Oman has put out to tender blocks *18A, 18B and 41 in its 2003 licensing round. Details can be found on the PGS website at* **www.pgs.com**

The Balal oil field in Iran has come *onstream, producing 20,000 b/d from two wells. Production will rise to 40,000 b/d after two additional wells come onstream in March 2004. The field has 390mn barrels of oil in place and is expected to produce 117mn barrels over its 15-year life.*

Russia & Central Asia

State-owned Turkmenburgaz is planning *a deep drilling programme this year in two new fields in*

In Brief

Turkmenistan's Unguz Garagum desert, reports Stella Zenkovich.*

Asia-Pacific

Murphy Oil and Petronas Carigali have *been awarded two production sharing contracts for deepwater blocks L and M offshore Malaysia.**

Malaysia has been awarded control *of part of the Celebes Sea by the International Court of Justice, enabling it to control local oil and gas prospecting, writes* Keith Nuthall.*

Indo-Pacific is understood to be *planning to develop the Kahil oil and gas field onshore New Zealand's Taranaki Basin, bringing it onstream in mid-2003.**

CNPC is reported to have made a major *gas discovery in China's Sichauan Province. The 160bn cm find comprises four fields, the largest of which – Luojiazhai – holds 58bn cm and is the biggest single reserve found in the basin to date.*

Petronas of Malaysia and PetroVietnam *are to jointly explore for oil in blocks 01/97 and 02/97 in the Con Son Basin offshore Vietnam.*

East Timor's Parliament is understood *to have ratified the Timor Sea Treaty, paving the way for joint oil and gas developments with Australia.**

PetroChina reports that it has pro- *duced 10mn t/y of oil from a field in Karamay, Xinjiang Province – claimed to be the first field to reach this target in western China to date.*

ConocoPhillips and CNOOC have *brought China's Peng Lai 19-3 field onstream. Located in block 11/05 in the Bohai Bay, the field is expected to produce between 35,000 b/d and 40,000 b/d during the first phase.**

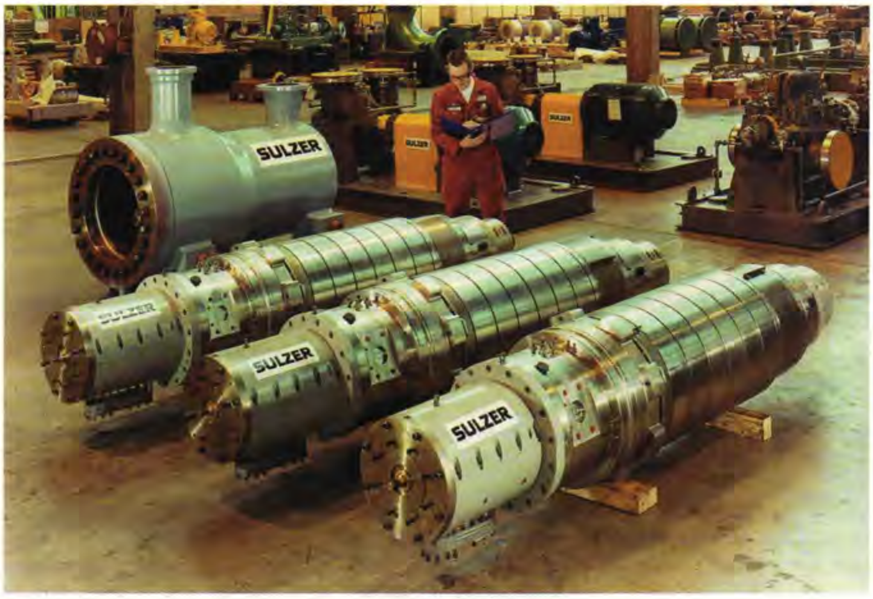
Latin America

The Mexican authorities are reported *to have unveiled plans to increase oil exports by 120,000 b/d to 1.88mn b/d from 1 February 2003.**

Petrobras has made an oil discovery in *Brazil's Santos Basin. The oil is reported to be 43° API, much lighter than the 24° API crude typically found in Brazil.*

NEWS Upstream

Providing a stimulating service



A contract worth in excess of €11mn was recently signed between pump manufacturer Sulzer and Yukos, Russia's second largest oil company. The contract covers the modernisation of 90 water injection pumps operated by Yukos subsidiary Yuganskneftegas in a bid to increase pump reliability and reduce energy consumption. A second contract, worth nearly €4mn, for modernising a further 36 pumps for Yukos subsidiary Tomskneft is expected to be signed shortly.

EC reacts swiftly to *Prestige* accident

The European Commission has reacted swiftly to the *Prestige* oil spill disaster off Spain, asking Ministers to immediately ban single-hull tankers aged 23 years and above from European Union (EU) waters while blocking single-hull vessels of any age from carrying heavy fuel oil to the EU, reports *Keith Nuthall.*

Brussels' new proposals would also speed up the existing timetable to phase-out all uses of any single-hull tanker, bringing deadlines forward to between 2005 and 2010. Loyola de Palacio, Transport and Energy EU Commissioner, said earlier rules agreed after the 1999 *Erika* disaster had been shown to be 'not sufficiently ambitious'.

The Commission had earlier published a blacklist of 66 ships that have been detained several times in European ports for failing to comply with maritime safety rules.

Meanwhile, the Organisation for Economic Cooperation and Development (OECD) will explore possible guidelines removing insurance taken out by shipowners against their own potential commercial losses caused by operating substandard ships. They would also promote compulsory insurance covering losses incurred by third-party victims of sub-standard shipping.

In addition, the UN Environment Programme has called for the creation of a 'stringent and demanding' liability system to encourage ship owners and masters to comply with higher standards and regulations on tanker safety.

North West Shelf gas supply to Kogas

Following the recent announcement of the sale of four LNG cargos to Korea, the North West Shelf LNG Sellers have signed a Letter of Intent (LOI) for a term contract for the supply of 0.5mn t/y of LNG to Korea Gas Corporation (Kogas). The LOI to negotiate a sale and purchase agreement will lead to the first LNG term contract signed between the North West Shelf LNG Sellers and Kogas.

Initial LNG volumes will be delivered in late 2003, building to 0.5mn t/y in 2004. The contract term is for seven years and the LNG will be delivered on an ex-ship basis.

The six equal participants in the North West Shelf Venture are: Woodside Energy, BHP Billiton, BP, ChevronTexaco, Japan Australia LNG and Shell.

Lukoil wins back West Qurna-2 contract

Lukoil has won back the contract to develop the 7.3bn barrel West Qurna-2 oil field in Iraq. The contract had been cancelled at the end of 2002 amidst claims by the Iraqis that Lukoil had failed to meet contract obligations. Lukoil, however, was alleged to have stated that the contract cancellation was in retaliation to Russia supporting the UN resolution on weapons inspections in Iraq.

The Iraqi Government has also awarded Gazprom a contract to develop a Western Desert oil field and a similar contract to develop part of the Rafidain oil field in the south of the country to a small company owned by Yury Shafranik, who served as Energy Minister under Boris Yeltsin. Some industry observers comment that the spate of contract awards to Russian companies may be aimed at getting Russia to continue to argue at the UN against war.

EA field onstream

Shell Petroleum Development Company (SPDC) has brought onstream the EA field in the shallow waters offshore Nigeria via the newly built *Sea Eagle* FPSO. The development plan includes the drilling of up to 55 wells, out of which 35 are already underway. Under the current phase of development, three production platforms have been constructed as well as the FPSO, its mooring system and several subsea pipelines and umbilicals. The *Sea Eagle* FPSO is designed to receive and process 170,000 b/d of liquids and 100mn cf/d of gas. It has a storage capacity of 1.4mn barrels of oil.

Output from the EA field is expected to increase Nigeria's production capacity by some 140,000 b/d of oil. The country has targeted production of 4mn b/d by 2010. EA gas is to be exported via an offshore gas gathering system currently under construction, to be converted to LNG at the Bonny Island Nigeria LNG plant.

New reg regime for Norwegian gas

The Norwegian Minister of Petroleum and Energy, Einar Steensnaes, recently presented Norway's new regulatory regime for gas transport in the Norwegian sector that includes comprehensive change in control and pricing of capacity in the gas transport system. New provisions ensure compatibility between Norwegian legislation and rules mandated by the EU Gas Directive for upstream gas pipelines.

The Norwegian gas transport system comprises more than 6,000 km of pipeline between Norway's offshore sector and mainland Norway, the UK and the European continent. The system transports some 12% of Europe's combined gas consumption.

Egyptian LNG project development

BG Group and partners have authorised start-up of the engineering, procurement and construction (EPC) early works programme for the proposed second train of the Egyptian LNG (ELNG) project located at Idku, some 50 km east of Alexandria. Train 2 is expected to cost $550mn. Bechtel, which is undertaking the $900mn EPC of Train 1, is to carry out the early works using design and construction subcontractors including Egyptian General Petroleum Corporation affiliated Petrojet and Enppi.

Train 1 is to produce 3.6mn t/y of LNG and is to be commissioned in 3Q2005. A total of 12 international banks and three Egyptian banks have been mandated to arrange financing for the first train, the entire output of which has been sold to Gaz de France under a 20-year agreement.

The second train, due onstream in mid-2006, will double output at the site. Gas will come from fields in the BG-operated West Delta Deep Marine concession, offshore the Nile Delta.

BP to sell Forties stake and GoM package

BP is planning to sell its 96.14% stake in the North Sea Forties field, together with a package of 61 shallow-water assets (mainly gas producers) in the Gulf of Mexico, to the US independent oil and gas company Apache for $1.3bn.

The sale is expected to 'improve returns on the group's upstream portfolio by reducing operating costs and freeing up capital for investment in other projects offering better profit margins'.

BP's share of production from Forties is some 48,000 boe/d, while its share from the Gulf of Mexico assets in the deal is around 71,000 boe/d. The company's share of the combined proved reserves for all the assets is 243mn boe.

In Brief

Petro-Canada has completed its *acquisition of a 50% working interest in the La Ceiba block in western Venezuela. The block was part of Petro-Canada's acquisition of the Veba Oil & Gas assets, the bulk of which closed in May 2002.**

Africa

TotalFinaElf and Sonangol have made *their 13th oil discovery in Angola's deepwater offshore block 17. The Zinia-1 discovery well flowed 3,650 b/d of oil.**

Repsol YPF (55%) has signed an *agreement under which it will explore, produce and operate block 401-d in Algeria's Berkine Basin in partnership with Woodside (35%) of Australia and Portuguese company Partex (10%).*

ChevronTexaco has made its ninth sig*nificant discovery in Angola's deepwater block 14. The Negage well flowed in excess of 8,630 b/d of 33° API oil during a drill stem test.**

Apache Coporation has announced a *new discovery on its Ras El Hekma concession in Egypt, its Emerald-1X well flowing 4,285 b/d of condensate and 16.9mn cf/d of gas.*

Eni is reported to have discovered new *gas reserves on the Tennin field in the Mediterranean Sea offshore Egypt. The exploration well flowed 700,000 cm/d of gas. Reserves are put at between 15bn and 30bn cm.*

FMC Technologies has been con*tracted by Sonatrach to develop five offshore loading stations for the transportation of oil and condensate from onshore facilities. The total project has been valued at $240mn and is to complete in 2004.**

IHS Energy has released a new study *that examines the petroleum systems and exploration prospectivity for the Western African Atlantic Margin (WAAM). It covers both onshore and offshore regions from Mauritania to Benin. For more information,* **e: bob.kay@ihsenergy.com**

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

In Brief

UK

The Institute of Petroleum (IP), *together with the UK Health and Safety Executive (HSE), is supporting a two-year research programme at the University of Surrey's Centre for Chronobiology under the direction of Professor J Arendt. The project is expected to finish by early 2005, although progress reports will be available from the IP website at* **www.petroleum.co.uk**

Europe

ABB has signed a $1.5bn credit facility *agreement with a group of 20 banks. The facility is secured by a package of ABB assets, including its Oil, Gas and Petrochemicals division that is earmarked for divestment in 2003.*

Gazprom is reported to have agreed *with Norsk Hydro swap operations on deliveries of gas to Europe.**

North America

Imperial Oil is pressing Canada's federal *government to fast-track regulatory procedures to speed its construction of a Mackenzie Delta pipeline. The Toronto-based company said it wants Arctic gas to start flowing by 2007.*

US-listed shipping company Teekay is *understood to be buying Statoil's Navion shipping business unit for $800mn.*

The Canadian Government is taking *steps to sell off its remaining 19% share of Petro-Canada, which is valued at approximately C$2.45bn, reports* Monica Dobie.*

Energy and Environmental Analysis is *reported to have forecast that US natural gas prices will average $5.37/mn Btu in 2003 and $5.35/mn Btu in 2004.*

The Board of Petro-Canada has *approved a $2,575mn capital expenditure budget for 2003. Some $670mn of this will be invested in oil sands.**

Middle East

Foster Wheeler has secured a contract *for the detailed engineering, procurement and construction of a new LNG*

NEWS Industry

Energy Charter Transit Protocol update

Negotiations among 51 European and Asian governments on a legally-binding agreement on energy transit issues, which have been underway for three years, were reported to be approaching finalisation following a meeting of the Energy Charter Conference member states in Brussels in December 2002.

The aim of the Energy Charter Transit Protocol is to establish a clear set of multilateral rules under international law on energy transit issues, thus helping to reduce the level of political risk associated in particular with oil and gas projects involving transit in the Eurasian area. The Protocol includes provisions on the methodology for setting transit tariffs, the provision of access to available capacity in pipeline systems for third-party shippers, and the eradication of unlawful taking of energy materials in transit.

Once the text has been finalised and prepared in all official languages of the Energy Charter process, the Energy Charter Conference will then complete the Transit Protocol's formal adoption.

However, despite this progress, consultations are set to continue concerning three issues on which certain delegations maintain reserves. In particular, agreement needs to be found over the implementation of the so-called Regional Integration clause included in the Protocol on the initiative of the EU, under which the Protocol's provisions will not apply to internal energy transportation within the EU, which will be governed by Community legislation.

Consultations will also continue concerning the Russian proposal for a 'right of first refusal' for transit shippers in the text of the Protocol – under which energy exporters with long-term supply contracts, whose short-term agreements for transit through third countries expire, would be given a right of preference to renew such agreements before transit capacity is offered to other parties – and on the issue of transit tariffs.

- **Iran and South Korea have become observers to the Energy Charter.**

Industry news in Russia and C. Asia

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

- The Lithuanian Government, 58% owner of gas utility Lietuvos Dujos, has extended Gazprom's deadline for acquiring a 34% equity in the gas utility until 28 February 2003 in order to reconcile a draft share purchase, gas supply, shareholders' agreements and company bylaws among current and potential equity owners, and to get those approved by Gazprom management.
- Contract signing has been postponed for the construction of the already long-delayed 285-km, $607mn onshore Bourgas–Alexandroupolis oil pipeline. The 700,000 b/d capacity pipeline is to carry Russian and Kazakh crude arriving by tanker from Novorossiysk, avoiding the Bosporus. Although Bulgarian-Greek 'political agreement' had earlier reportedly been reached at the level of Prime Ministers, Bulgarian Regional Development Minister Hasan Hasan is understood to have already started negotiations with 11 contractors.
- Moldova is reported to be drifting towards a debt-for-equity swap concerning the $800mn it owes to Russia, primarily for gas supplied. However, some $600mn of the debt has been accumulated by the breakaway province of Transdnistria, populated by ethnic Russians (Red Army remnants and their families). The controversial cancellation by the Supreme Court in Chisianu of the sale of five regional current distribution grids to Spain's Union Fenosa by the former government is thought to be a step in this direction.
- In accordance with the International Monetary Fund's (IMF) demand, Bosnian fuel prices and taxes, both direct and in-direct, are being harmonised and will, in due course, be standardised by the two constituent entities of Bosnia-Hercegovina, the Muslim-Croat Federation and the Respublika Srpska, as well as the former's Brcko District.
- Aiming to persuade the IMF to release the next $17mn credit tranche, the Azeri Government has increased fuel prices at the pumps from $50/t to $150/t while leaving them unchanged for water, gas and power utilities and state companies. Meanwhile, the gas tariff has been increased to $87/1,000 cm to reflect 'real costs', since Azerbaijan gets Russian gas for $52/1,000 cm at the border and the cost of transportation via the pipelines of Azerigaz is $35/1,000 cm.

Change for CPC

The Russian Federal Energy Commission is understood to be proposing to change the status of the Caspian Pipeline Consortium system to a natural monopoly. 'This would enable the FEC to set government tariffs for CPC transport services and also require the CPC to intake crude oil from independent producers, including Russian companies,' explains UFG. At present the CPC capacity is only 30% utilised. It has been argued that the present charging structure for shipping oil across Russia to the Black Sea allows CPC to reduce earnings and tax payments.

UFG predicts that the consortium shareholders, including ChevronTexaco, Lukarco, Rosneft-Shell, Mobil, Agip, BG and Oryx, will oppose any such change in status. The analyst also predicts the situation could become a 'political situation that may threaten Russia's investment attractiveness for strategic investors going forward'.

Adria flow reversed

Six nations, including Russia, have signed an agreement to reverse the flow of the Adria pipeline to carry between 100,000 and 300,000 b/d of oil to the Croatian port of Omisalj, reports UFG.

In addition, the Druzhba and Adria pipelines are to be integrated in order to carry Russian oil directly to the Adriatic coast, covering some 3,200 km.

Yukos and TNK are understood to have committed to shipping 50,000 b/d of oil through the pipeline.

'For Yukos, this new route will open new opportunities for its US deliveries,' states the analyst, 'as well as improving the economics of its US exports, as the oil company will be able to avoid the Black Sea–Mediterranean–US route that has involved expensive transshipments from smaller tankers to VLCCs.'

BP to open new LNG import terminal in Italy

BG is to construct and operate a €330mn LNG import terminal in Brindisi Port on the southeast coast of Italy. The regasification terminal will be constructed in two phases and is to be commissioned in 2006. Phase 1 envisages throughput of 3mn t/y, rising to 6mn t/y in the second phase.

Italy is a net importer of gas and currently has one LNG receiving terminal in operation on the northwest coast. Over the last decade energy demand has been continually growing and in 2010 is forecast to be about 25–30% higher than today's present demand. Growth will predominantly be driven by the power generation sector.

The terminal is located on the Mediterranean Sea and will receive imports from North Africa and the Gulf states. It is located within 5 km of Snam Rete Gas' 29,600-km national gas transmission and distribution network.

Opec to bring about own demise?

Julian Lee, Senior Energy Analyst at the London-based Centre for Global Energy Studies (CGES) has warned that Opec could bring about its own demise by sticking to its policy of defending oil prices at the expense of its market share despite its success in recent years in preventing a price collapse.

He warned that as cartels have a natural tendancy to push prices too high two undesirable consequences result – lower demand and greater supplies from outside the cartel.

Over time this lower overall demand and increased non-cartel production may fragment the industry and consequently weaken the cartel.

This, in turn, helps foster the 'free rider' problem that could lead to the slow unraveling of the cartel and its subsequent disintegration.

Opec's market share has fallen from 51% of global production in 1970 to 33% today.

Oil men and women on New Year Honours list

Shell Chairman Phillip Watts was awarded a Knighthood in the 2003 New Year Honours, in recognition of his services to British business and his role in chairing the World Business Council for Sustainable Development.

Peter Lehmann, Chairman of the Energy Saving Trust and Chairman of the Fuel Poverty Advisory Group, was awarded a CBE for services to the gas and energy industry and its customers. OBEs were awarded to Lynda Armstrong, Director of New Business Development at Shell UK, for services to the UK oil and gas industry, and to John Mumford, BP Oil UK Director, for services to the environment.

In Brief

*train at Qalhat in Oman. The new train is to be commissioned by the end of 2005 in order to supply of LNG to Union Fenosa in early 2006.**

***Egypt is understood to be set to supply** Jordan with gas via a new gas pipeline in May 2003.**

***It has been reported in the media that** a second pipeline has opened between Syria and Iraq, based on evidence from recent satellite images.**

Russia & Central Asia

***Invest-Oil, an affiliated company of** Sibneft and Tyumen Oil Company (TNK), has successfully bid $1.86bn for the 74.95% government stake in Slavneft.**

Asia-Pacific

***CNOOC is reported to have posted** profits of Yuan 11.05bn for 2002, up 14.4% from 2001.*

***Apache Corporation reports that the** Harriet joint venture has finalised a contract to supply more than 600bn cf of gas over 25 years to the Burrup Fertilisers plant that is to be built in Western Australia.**

***The Indian Government is understood** to have approved the sale of Bharat Petroleum and Hindustan Petroleum in which it holds 66% and 51% stakes respectively.*

Latin America

***Work on the $400mn Yacuiba-Grande** River (Gasyrg) gas pipeline, also known as the Bolivia–Brazil pipeline, is reported to have completed.*

Africa

***Belgium's Distrigas is understood to** have signed a new gas supply agreement with Sonatrach of Algeria covering the supply of at least 1bn cmly of gas to Spain by 2006. Sonatrach will transport the gas via the 8bn cmly capacity Medgaz pipeline that is currently under construction.*

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In Brief

UK

Patron Capital has completed the *acquisition of Simon Storage from Simon Group and also acquired Vopak's 49.99% stake in the five terminals formerly operated by the Chemicals and Oil Storage Management (COSM) joint venture with Simon. The total consideration for both transactions is £88mn.*

The International Petroleum Exchange's *gas futures set a new daily record of 70,373 lots on 8 January 2002.**

UK supply chain solution provider *Wincanton is proposing to acquire pan-European contract logistics provider P&O Trans European on a debt-free basis for £152.5mn in cash.**

Argent Energy is reported to be planning *to build a £10mn plant at Newarthill, Motherwell, that will convert used cooking oil into 50mn litres of biodiesel fuel annually. Claimed to be the first large-scale biodiesel production unit in Scotland, the facility is expected to be commissioned in 2004.*

Europe

Eni has acquired 130 service stations *in Spain from Saras Energia for an undisclosed sum. Total throughput at the sites is 320mn litres. The deal will boost the Italian company's fuel retail market share to 5%.*

BP is to sell 494 of its service stations *in north and northeast Germany to Polish fuel retailer PKN Orlen for $140mn in cash, including the assumption of debt.**

Shell has acquired 86 service stations *in Italy from Agip. The deal follows its acquisition of Erg sites in northern Italy in 2000 and, more recently, the acquisition of a private network of some 90 sites currently trading under different brand names in the country.**

Eni of Italy is to acquire a 50% stake in *Spain's Union Fenosa Gas for €440mn. The Spanish gas market is to be liberalised from 2003 and domestic demand is forecast to rise by 10%/y to reach 42bn cm by 2010.*

Eastern Europe

Stella Zenkovich ***reports that the Polish*** *Government has revised its strategy*

NEWS Downstream

i2 and Shell cut SCM costs

i2 Technologies, a leading provider of end-to-end supply chain management (SCM) solutions, and Shell Global Solutions have completed the design phase of i2 Downstream Oil, a modular, end-to-end SCM suite for the downstream oil industry. One of the first elements – i2 Demand Planner Downstream Oil – is beginning to be deployed at Shell Oil Products US.

'The completion of this critical phase in design is a significant milestone in our efforts to help customers in the petroleum industry transform their value chains and achieve overall savings,' comments Amir Kazmi, Vice President and General Manager, i2 Global Energy & Chemicals business unit.

The i2 Downstream Oil software suite has been designed to improve business operations from crude oil acquisition to terminal and depot management by streamlining the complex matrix of logistics, manufacturing, marketing and sales activities of the downstream oil value chain. It helps companies examine their supply chain practices to find opportunities to improve operational efficiencies and achieve bottom line savings.

Based on i2's platform of supply chain solutions i2 Downstream Oil will include modules for demand planning and fulfillment, supply chain planning across a network of manufacturing and distribution sites, and distribution and refinery scheduling. The solution is intended to provide the following customer benefits:

- **Optimised margins across the entire supply chain network and within individual refineries.**
- **Increased revenues from greater flexibility and responsiveness to market opportunities.**
- **Reduced operating costs through improved stability of refinery and distribution operations.**
- **Reduced crude acquisition costs via improved alignment of crude selection with end product demand.**
- **Reduced overheads due to synchronised decision support system.**

News from the European Commission

The European Commission has welcomed a landmark competition agreement with Nigeria LNG, which has agreed to stop preventing its European customers from reselling gas outside their own EU Member States. The Commission has two similar competition inquiries underway, involving Gazprom of Russia and Sonatrach of Algeria, reports *Keith Nuthall.*

Meanwhile, new rules changing the place of taxation for VAT on natural gas have been proposed by the Commission, so that where the buyer was a trader reselling supplies, the place of taxation would be where the buyer was established and if the sale was to a final consumer, taxation would be levied at the place of consumption.

The Commission has also proposed new fuel quality limits for EU ships, capping sulphur content at 1.5% for vessels in the North Sea, English Channel and the Baltic and by passenger ferries on regular services. It has also proposed a 0.2% sulphur limit for fuel in berthed ships.

In other news, the European Court of Justice has ruled petrol suppliers can claim VAT rebates taking into account what they have spent honouring the money-off coupons issued by petrol retailers. The German Government had blocked such tax refunds where vouchers are handled by an agency.

In addition, political agreement has been struck at the Council of Ministers over proposals to deepen the liberalisation of the EU gas market. The legislation will now receive a second reading at the European Parliament.

Statoil secures UK gas storage rights

Statoil has acquired the development rights for an underground gas storage facility to be built at Aldbrough on the UK east coast, northeast of Hull, following its purchase of Aldbrough Gas Storage Company from Intergen (a Shell/Bechtel joint venture). The new facility will act as a buffer against possible terminal interruptions and will provide additional security of supply for the Norwegian company's gas deliveries to the UK market.

A total of three underground salt caverns are to be prepared to receive between 170mn and 230mn cm of gas. The project will also involve the construction of an 8-km gas pipeline connection tied into the UK national transmission system, a power line connection to the Yorkshire Electricity distribution network and a seawater leaching system. The facility is slated to be ready in 2007.

Centrica expands Canadian operations

Centrica is planning to acquire the retail gas and electricity supply businesses of the ATCO Group in Alberta, Canada, for C$128.5mn, payable over two years. ATCO is the main regulated gas supplier in Alberta, supplying gas to approximately 80% of Alberta consumers (some 821,000 customers) and electricity to 14% of the market (167,000 customers). Coupled with its acquisition of Texas-based AEP, with 860,000 customers, the deal means Centrica will be serving almost 5.5mn customers in North America.

In Canada, Centrica's Direct Energy business will become the largest supplier of energy and services to homes and small businesses, with almost 4mn customers. The company intends to use the ATCO acquisition as 'a platform to expand in a deregulated Alberta market, particularly in electricity through dual fuel fixed price energy contracts.'

There are 1mn gas customers and 1.2mn electricity customers across the province, most of whom already take gas from ATCO. In addition, Direct Energy also plans to introduce a range of home services, including the installation, maintenance and repair of residential heating, ventilation and air conditioning systems.

Middle East and African developments

Stella Zenkovich reports on recent Middle East and African downstream news:

- An agreement has been concluded by Qatar Petroleum, ExxonMobil and TotalFinaElf to design and build a $400mn, 140,000 b/d gas condensate refinery to be operated by Qatargas. To be commissioned by the end of 2006, the facility in Qatar will produce mainly naphta that will be used as petrochemical feedstock, as well as smaller volumes of LPG for export.
- The consortium of Toyo, Dailem and Idro-Iran has made a $1,205.7bn bid to construct six onshore gas condensate refineries for phases 6, 7 and 8 of Iran's South Pars gas field project. The refineries will produce 120,000 b/d of condensate gas and 128,000 cm/d of dry and sour methane gas.
- A Japanese consortium comprising JGC Corporation and Chiyoda Corporation has won a $879mn contract to build the 75,000 b/d Sohar oil refinery, located 250 km southwest of Muscat. Due to be commissioned in 2Q2006, the facility will export 90% of its output.
- Shell Marketing Gambia has ceased its LPG operations after two decades, Director General Jean Claude Djene has announced.
- National Oil & Chemical Marketing (NOLCHEM) is to build four LPG plants in Nigeria, Managing Director Owen Tychus has announced, in Lagos, Port Harcourt, Kano and Kaduna. The pilot plant in Lagos is already under construction.
- Although the National Oil Company of Zimbabwe (NOLCZIM) recently released 3mn litres of petrol countrywide and is claiming to have further volumes available, the fuel shortage situation in the country is reported to remain desperate.

Petrobras apportions pipeline capacity

BG Group and state-owned Petrobras have signed an agreement to assign a proportion of Petrobras' 30mn cm/d of firm capacity in the Bolivia–Brazil pipeline Transportadora Brasiliera Gasoduto (TBG) to BG Brazil. It is claimed to be the first time that such capacity in TBG has been assigned and will allow BG to continue to supply the growing gas market in the Comgas area.

BG has also extended its existing gas sales agreement with Comgas, the largest gas distribution company in the state of Sao Paulo, Brazil, and in which BG holds a 60.5% interest. BG is contracted to supply 650,000 cm/d of gas, produced from its 100% owned La Vertiente field in Bolivia, from 2003 to 2011. The gas will be sold to Comgas principally for use in the industrial and co-generation sectors.

ICE and Nymex locked in court case

InterContinentalExchange (ICE) reports that it has filed a suit in the US against Nymex, seeking to prevent the latter from 'abusing its monopoly power in the market for trading and clearing North American energy futures contracts and extending its monopoly into the market for over-the-counter (OTC) energy trading. ICE's claim, made as part of a counterclaim in an action initiated by Nymex, asserts that Nymex's efforts to prevent ICE from using Nymex settlement prices by claiming that these prices are copyrightable works of 'authorship' represents 'an illegal restraint of trade and is intended solely to restrict competition'.

In Brief

*concerning the privatisation of its fuel sector, deeming that instead of two there will be only one major production centre. This implies the merging of PKN Orlen and Rafineria Gdanska (RG) and the final ousting of Lukoil, barring the Russian company from acquiring an RG stake.**

North America

***ChevronTexaco has reached agreement** with Dynegy to end existing natural gas purchase and sale contracts and other related contracts from 1 February 2003. As part of the deal Dynegy will provide ChevronTexaco with transition services. ChevronTexaco's new wholesale natural gas marketing unit – ChevronTexaco Natural Gas – will be fully operational from April 2003.**

***CMS Energy Corporation is reported to** be selling its gas pipeline business to Southern Union Company for $662mn and the assumption of $1.17bn in debt. CMS is also understood to be selling its gas trading book contracts to Sempra Energy of Canada as part of a strategy to raise $2.7bn by the close of 2002.**

Middle East

***Shell and Pars Oil have set up a new** joint venture, Pars and Shell Private Joint Stock Company, that will deliver Shell lubricants to customers in Iran.*

***Gazprom is understood to be planning** to boost long-term and spot sales to Europe in 2003, primarily in the UK, Italy, Turkey and the Netherlands.*

Russia & Central Asia

***Britain's JKX Oil and Gas has finally** wrested full control of Poltava Petroleum (PP) from the Ukrainian State Property Fund, which sold it the final 33% of state-held equity following a six-year legal wrangle, reports* Stella Zenkovich.

***BP and Citibank are understood to be** jointly expanding their retail operations in Russia, with Citibank installing automated teller machines (ATMs) at each of BP's 39 sites in Moscow.**

Asia-Pacific

***India's first LNG import terminal at** Dahej in Gujaret is reported to be 70%*

In Brief

complete and on target to receive first gas in 1Q2004. The terminal will be capable of receiving 5mn t/y.

Africa

***Shell Nigeria Gas has reported that** more than 30 industrial customers in Nigeria's Ogun State have signed up for gas supply from the company's $34mn Agbara/Ota gas transmission and distribution project.**

***Eni and ChevronTexaco's 25-MW ther-**moelectric power plant at Djeno in the Republic of Congo has been commissioned. The $32mn plant is supplied with associated gas from the Kitina, Djambala and Foukanda projects that are producing 26,000 b/d of oil.**

NEWS Downstream

Australian energy market reform

The Council of Australian Government's Energy Market Review (EMR) has published a number of recommendations for energy market reform in its final report entitled *Towards a Truly National and Efficient Energy Market.* It has endorsed:

- the need to commence the independent review of the gas access regime and to address the deficiencies with current access regulation identified by the Productivity Commission;
- the need for greater upstream gas market competition;
- the principle that significant regulatory decisions should be subject to clear merits and judicial review; and
- the need to avoid restrictions on retail energy prices.

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

It has also recommended the establishment of a single National Energy Regulator and suggested that 15-year 'economic regulation free' periods be introduced for greenfields gas transmission pipelines in order to encourage the development of such infrastructure.

UK Deliveries into Consumption (tonnes)

Products	†Oct 2001	†Oct 2002	†Jan–Oct 2001	†Jan–Oct 2002	% Change
Naphtha/LDF	102,550	161,270	1,324,712	1,149,596	–13
ATF – Kerosene	847,506	998,778	8,793,404	8,700,772	–1
Petrol	–	–	–	–	–
of which unleaded	1,686,598	1,594,669	16,680,719	16,222,371	–3
of which Super unleaded	44,795	61,128	345,064	486,673	41
of which Premium unleaded	–	–	5,465,882	–	–100
ULSP (ultra low sulfur petrol)	1,641,803	1,533,541	10,869,773	15,735,698	45
Lead Replacement Petrol (LRP)	64,559	32,615	757,190	456,660	–40
Burning Oil	298,010	311,310	3,603,140	3,025,507	–16
Automotive Diesel	1,393,283	1,531,347	13,271,541	14,123,219	6.4
Gas/Diesel Oil	502,332	514,771	4,788,016	5,028,729	5
Fuel Oil	124,123	157,771	1,683,542	1,551,329	–8
Lubricating Oil	78,521	56,955	763,343	673,299	–12
Other Products	646,187	699,326	6,409,344	6,794,808	6
Total above	5,743,669	6,058,782	58,451,917	57,726,290	–1
Refinery Consumption	372,257	361,858	4,075,914	4,093,086	0
Total all products	6,115,926	6,420,640	62,527,831	61,819,376	–1

Products	†Nov 2001	†Nov 2002	†Jan–Nov 2001	†Jan–Nov 2002	% Change
Naphtha/LDF	94,627	218,122	1,419,339	1,367,718	–4
ATF – Kerosene	695,855	799,352	9,489,259	9,500,124	0
Petrol	–	–	–	–	–
of which unleaded	1,661,591	1,606,839	18,342,310	17,829,210	–3
of which Super unleaded	43,361	61,957	388,425	548,630	41
of which Premium unleaded	–	–	5,465,882	–	–100
ULSP (ultra low sulfur petrol)	1,618,230	1,544,882	12,488,003	17,280,580	38
Lead Replacement Petrol (LRP)	58,534	31,146	815,724	487,806	–40
Burning Oil	354,847	350,640	3,957,987	3,376,147	–15
Automotive Diesel	1,480,252	1,505,782	14,751,793	15,629,001	5.9
Gas/Diesel Oil	545,216	505,864	5,333,232	5,534,593	4
Fuel Oil	161,613	206,669	1,845,155	1,757,998	–5
Lubricating Oil	79,291	60,032	842,634	733,331	–13
Other Products	589,623	631,049	6,998,967	7,425,857	6
Total above	5,721,449	5,915,495	64,173,366	63,641,785	–1
Refinery Consumption	474,532	361,337	4,550,446	4,454,423	–2
Total all products	6,195,981	6,276,832	68,723,812	68,096,208	–1

† Revised with adjustments

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

Future deepwater prospects

The serious decline in the size of new discoveries in the mature shallow-water areas of the world has resulted in the major operators leaving provinces such as the North Sea to invest in the deepwater areas where major fields are still to be found. The size of average field development prospects in waters deeper than 1,000 metres is twice that of those in shallow waters. *Dominic Harbinson* and *John Westwood* of Douglas-Westwood, and Infield Systems' *Dr Roger Knight* report.

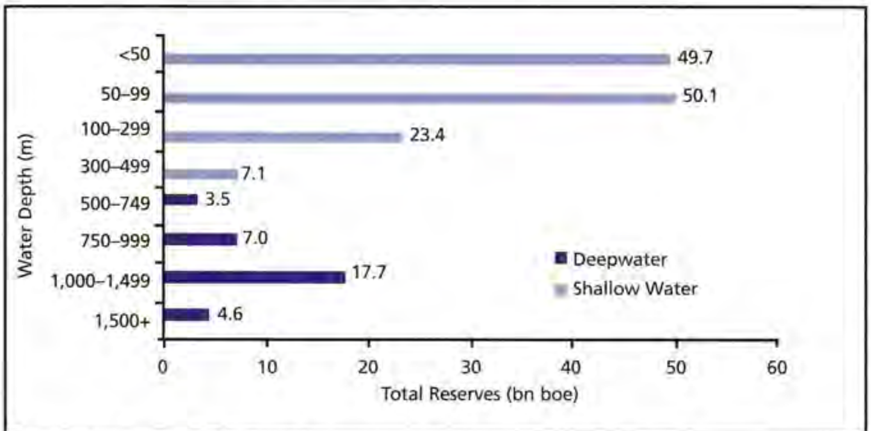

Figure 1: Reserves of offshore field prospects, 2003–2007, by water depth
Source: The World Deepwater Report 2003–2007, *Douglas-Westwood and Infield Systems*

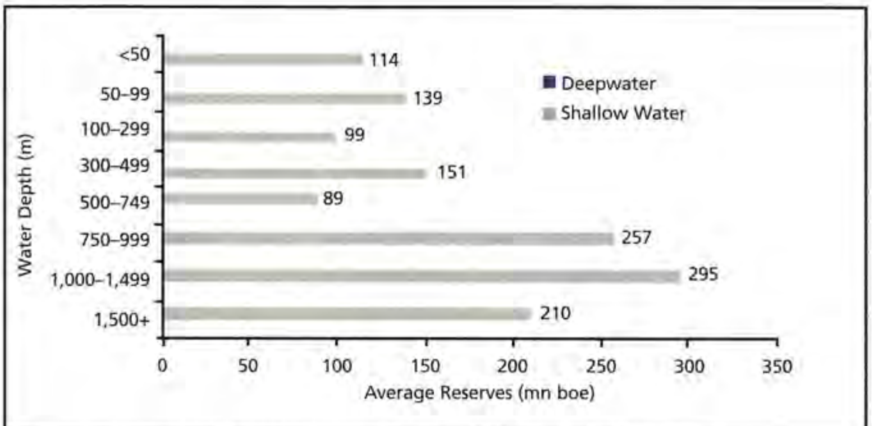

Figure 2: Average field prospect reserve size, 2003–2007, by water depth
Source: The World Deepwater Report 2003–2007, *Douglas-Westwood and Infield Systems*

For some years the authors' companies have been tracking deepwater activity and forecasting future expenditure in this most important business sector. This article summarises the results of the most recent edition of their study, *The World Deepwater Report*. It considers individual field development prospects for the period 2003–2007, the likelihood of them going ahead and forecasts the probable numbers of deepwater subsea and platform completed wells, km of flowlines and control cables, and numbers of templates and manifolds. From these totals annual capital expenditure is forecast for each region of the world.

The authors also consider the technical challenges faced by the industry as it moves into ever greater water depths. From the offshore industry's beginnings in the 1940s it took nearly three decades to achieve production from 100 metres water depth and two more decades to reach nearly 2,000 metres, but this decade production from nearly 3,000 metres is already under consideration.

Meanwhile world oil demand continues to grow. A further recently-completed study, *The World Oil Supply Report 2002–2050*, casts doubt on the ability of existing onshore and shallow-water regions to supply future needs, further reinforcing the authors' belief in the importance of exploration and production in deepwater.

Into the deep

When we began our analysis of the prospects offered by the deepwater sector six years ago, deepwater was regarded as beginning at a water depth (WD) of 200 metres, that is, the edge of the continental shelf. By 1998 the definition had shifted to 300 metres. Today the generally accepted threshold is 500 metres and we use this in the analysis that follows.

What is driving this move into the deep? Since 1965 there has been a 240% increase in world energy consumption. Much of this has been sourced from an increased use of hydrocarbons. A major factor in this strengthening of demand has been population growth. Since 1970 the world's population has increased from 4bn to 6bn and the current growth rate is about 1bn every 12 to 14 years. Oil consumption has grown from 40mn b/d to 75mn b/d and forecasts are for demand to grow to 112mn b/d by 2020. This raises the question of where all this extra oil will come from. Due to the security of supply issues associated with the major sources of onshore oil, the short answer is that more and more oil must come from offshore.

The problem with this is that shallow water reserves are being produced at an alarming rate and most new discoveries are a fraction of the size of earlier ones. Off the shores of Europe for example, the size of the average field brought onstream in the last five years was about 90mn boe; over the next five years it will be less than half that. In response to this decline the oil majors are 'voting with their dollars' and turning their attention away from mature areas such as the shallow water Gulf of Mexico and the North Sea to invest in deepwater areas where there is still potential for billion-barrel discoveries.

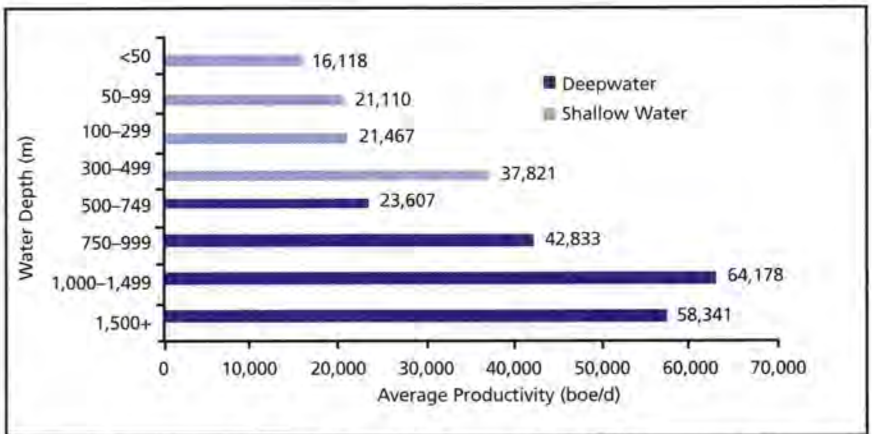

Figure 3: Average productivity of future field prospects, 2003–2007, by water depth
Source: **The World Deepwater Report 2003–2007,** ***Douglas-Westwood and Infield Systems***

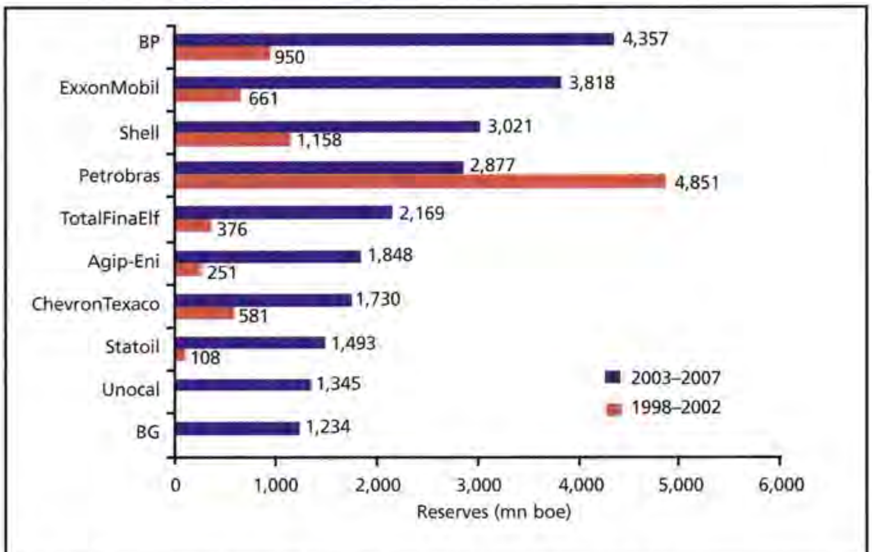

Figure 4: Deepwater reserves held by the top ten companies, 1998–2007
Source: **The World Deepwater Report 2003–2007,** ***Douglas-Westwood and Infield Systems***

Figure 1 shows that shallow water still holds large reserves, but in reality much of this is associated with a few Middle Eastern 'giants'. To get a clearer picture of the significance of the hydrocarbon volumes held in deepwater reservoirs it is necessary to consider the average reserves per field over the same range of water depths. **Figure 2** shows that the average size of future field development prospects increase dramatically as the water depth (WD) threshold of 500 metres is passed and it peaks at around the 1,500 metres mark. **Figures 1** and **2** both graphically illustrate the importance of the ultradeep, that is, beyond 1,000 metres. Also, as shown in **Figure 3**, the average productivity of deepwater fields is higher than those in shallow waters.

Finally, the prospects for new discoveries remain good. Roncador – the king of Brazil's deepwater 'elephants' – was only discovered after 200 exploratory wells had been drilled in the Campos Basin and more than a decade after the discovery of the country's second largest field, Marlim. Similarly, in the Gulf of Mexico, the 1999 discovery of Thunder Horse (with reserves of 1bn boe) came more than 10 years and 250 exploration wells after the finding of the Mars field, the region's previous 'top dog' discovery (with reserves of 705mn boe). It therefore seems reasonable to surmise that more intense exploratory efforts targeting deepwater prospects will result in substantial reserve increases.

Deepwater activity is also being driven by secondary factors, in particular:

- *Technological advances* – improvements and innovations, particularly in the drilling, floating production and subsea sectors, have proved especially beneficial in the exploitation of deepwater prospects.
- *Reduced costs* – improved technologies have dramatically reduced both capital and operating expenditure (capex and opex), enabling deepwater projects to achieve cost profiles that are increasingly similar to those in shallow waters.
- *Improved commercial practices* – changes to the way offshore developments are being realised have enhanced project efficiency and played a major role in the cost reductions noted above. Over the past decade, operators, contractors and supply companies have become leaner and able to operate with lower margins than ever before, and the offshore oil and gas industry generally has become more robust to movements in the oil price.
- *Government support* – this has made an important contribution to increased industry efficiency by means of favourable fiscal policies, funding R&D, encouraging training and promoting best practice.

The common feature shared by each of these inter-related factors is that they tend to reduce the level of risk associated with deepwater activity. The bottom line is that in the period 1998 to 2002 deepwater fields with reserves totalling 10.6bn boe were bought onstream – the prospects under consideration for the next five years total 32.8bn boe.

Figure 4 shows the reserve holdings of the top ten oil companies in the deepwater sector. The figure is drawn from information contained in the Infield Systems Participants Database which tracks oil company participation in offshore projects worldwide. It expresses company reserve holdings – whether as operators or as non-operating participants – in deepwater fields developed or targeted for production over the 1998–2007 period.

Seen from this perspective the historic dominance of Petrobras, which enjoyed a monopoly of deepwater action in

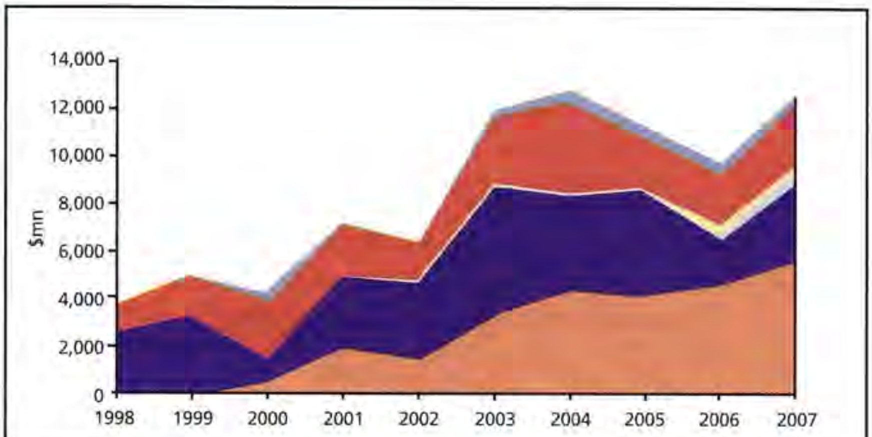

Figure 5: Deepwater capital expenditure – historic and forecast
Source: The World Deepwater Report 2003–2007, *Douglas-Westwood and Infield Systems*

Brazil's Campos Basin, is very clear. However, based on reserves held in fields due onstream over the coming five years the three super-majors – BP, ExxonMobil and Shell – are expected to overtake the Brazilian national operator, while TotalFinaElf also features strongly. Over the 2003–2007 period Petrobras and Shell are likely to be joined by the other eight companies shown as members of the 'billion barrel plus' deepwater club. Taken together, these ten companies account for 73% of the deepwater reserves identified for development over the 2003–2007 period.

Deepwater capex

Our latest forecast of capital expenditure in the deepwater sector (see **Figure 5**) indicates that over the past five years some $26bn was spent bringing onstream 10.6bn boe of deepwater reserves. Over the next five years, 2003–2007, industry is expected to spend $56bn. Our analysis suggests that 93% of this $56bn will be spent in the 'golden triangle' of Brazil, the US Gulf of Mexico and West Africa. Three main elements dominate this forecast capital expenditure:

- floating production systems (FPSs) of various types, with a total spend over the period of $21bn;
- drilling and completion of deepwater production and injection wells which is expected to require a similar level of expenditure;
- pipelines and control lines, with an estimated spend of $11bn.

Platform expenditure is forecast to peak in 2004 because of the large number of significant FPSs due then – these include semi-submersibles on Thunder Horse, Roncador and Marlim Sul; FPSOs on Kizomba A, Akpo and Albacora Leste; the Mad Dog spar; and TLPs on Kizomba A and Magnolia.

Technical challenges

As suggested in the forecasts above, three elements – platforms, wells and flowlines/risers – dominate deepwater sector expenditure. The relative importance of these varies by region and type of development. For example, in the Gulf of Mexico, where there are large numbers of subsea tieback prospects, flowline and drilling costs are most significant.

Wells – As water depths increase so do drilling and completion costs and considerable efforts are underway worldwide to constrain these. The ultimate objective must be to maximise well productivity and thereby enable a reduction in well numbers. Techniques such as large bore completions, multilateral highly deviated wells, and 'smart wells' offer great prospects.

Flowlines – Our surveys of oil company R&D interests show deepwater flow assurance as a major area of concern. Problems range from developing low-pressure reservoirs to flowline-blocking hydrate formation. At present few oil flowlines exceed 20 km, although 100-km plus gas flowlines exist in the Gulf of Mexico. The prize for increasing flow distances is huge and has been much discussed. In a number of situations such as off West Africa, low reservoir energy limits flow distances significantly, particularly when oil has to be raised to the surface through great water depths.

There are a number of alternatives under development and initial trials, including subsea separation, multiphase pumping, downhole pumps, etc. However, most of these subsea solutions require large amounts of electrical energy to be transmitted to the wellhead. The industry view seems to be that, in practice, conventional means of energy transmission subsea are limited to about 30 km. Beyond that, a step change in costs is incurred and new solutions are required.

Although TLPs have been well-used in the deep waters of the Gulf of Mexico, we understand that work by Shell has suggested they may have a practical limit of 1,500 metres water depth. For the 'ultra deep' it seems that the future will see continued use of the tried-and-tested FPSO and semi-submersible solutions although a number of new floating concepts are also under discussion. A case in point is West Africa where relatively benign environmental conditions have allowed for low-cost innovative production systems to be proposed, designs that would be impractical in harsher environments.

There are also concerns over the intervention costs for subsea-completed wells, particularly in remote areas where intervention facilities are not readily available. An area of major interest is therefore the use of 'dry' surface-based well completions on platforms rather than using subsea wells. This dry wellhead capability is one of the major drivers behind the significant interest in the spar platform concept. The industry has had relatively little experience with spars to date – there are currently only six such units installed worldwide, all of which are located in the deep waters of the US Gulf. The first of these – Kerr-McGee's Neptune spar – dates back to 1996, with BP's Horn Mountain being the most recent addition to the fleet.

Resource shortages

The 'rationalisation' of human resources following the last oil price downturn has forced operators to postpone or 'slow-track' projects because they do not have sufficient project managers to progress all field developments in their corporate portfolios.

Contractors also have the same problems and are reporting unprecedented shortages of people and equipment. Following each downturn many of the more highly-skilled people (who can readily find employment elsewhere) have left the industry, not to return. This is coupled with the fact that in the past the offshore industry has done little to attract young, high-capability people, so human resources are rapidly becoming the factor limiting the industry's future growth prospects. Training is not necessarily the answer – skills can be acquired fairly rapidly, experience cannot! We are concerned that some major contractors may have insufficient capacity (physical and personnel) to undertake more than one or two large-scale projects. In one case we understand that the average age of a project manager is 53 and over-45s out-number under-45s by 12:1!

Although everyone is aware of the situation, in reality far more still needs to be done to address the problem, perhaps by finding better ways of using the huge potential skill pools of the developing world.

Shortage of experience

Although in practice deepwater only represents a small part of global offshore activity it is without doubt the technological leading edge and the future prospects are considerable. While there have been many great achievements in deepwaters there will undoubtedly be many surprises ahead.

In reality there are very few players, both contractors and oil companies, who have real knowledge and experience of the deep frontier. A number of the newer oil company players will have to face a very steep, and, if they are not careful, expensive, learning curve.

Where the majors have great advantage is that with a large portfolio of field development prospects they can afford to take a measured risk on some of them. However, as we have seen in the past, in the offshore industry as in many others, the level of innovation is sometimes inversely proportional to company size and many of the oil industry's leading-edge developments have been due to the efforts of the smaller players.

Can the industry deliver?

Over the past few years we have had an increasing concern over the ability of the industry to deliver the goods and services required by the operators at the price they are prepared to pay. As we see it there are two main issues – limited human resources discussed above and contractors' low profitability.

Risk and reward for the contractor community has got out of balance. It is now obvious that the present EPIC contracting system has pushed too much risk on to contractors and new working methods must be developed. Lump-sum contracts are fine for commodity products, but we question if they are appropriate for the leading edge of such a demanding industry. In the final analysis, the deepwater oil and gas industry is dependent upon the existence of profitable contractors.

How deep could it get?

Within a few years fantastic progress has been made, but how deep can the industry really go? The Campos Basin is stated by Petrobras to extend down to 3,400 metres and, off West Africa, there have been reports from seismic companies of 'interesting' seismic returns from water depths of 4,000 metres. But just how long might it take to get there? A new drilling record was established late in 2001 when the *Discoverer Spirit* drillship spudded a well in WD 2,967 metres (9,727 ft) on Unocal's Trident prospect in the Gulf of Mexico, but the production depth record – currently just above WD 2,300 metres – is still a long way behind.

At first sight, to tackle production from such great depths seems to demand not only a step change in technology, but also a massive acceleration in the speed of progress. However, we tend to forget that during each decade the progress into great depths has been accelerating. We have calculated that at the speed of progress in the 1970s production from 1,000 metres would not have been achieved until 2015 – in fact it was achieved in 1995. In the 1980s the trend suggested that the present production record would not have been reached until after 2015. The trend through the 1990s now suggests that 4,000 metres will not be reached until 2015. Who is taking bets it that will be sooner?

New production solutions reducing subsea costs

The capabilities of subsea production systems have grown steadily over the past few years, with longer step-outs and growing acceptance of technology for flow metering, boosting and subsea processing. However, the recovery from subsea wells remains lower than that from platform wells – a problem that could be overcome by more cost-effective subsea well intervention. Where dry-trees are needed, the use of lightweight materials could help bring down costs for the next generation of ultra-deepwater platforms. *Jeff Crook* reports.

The TotalFinaElf-operated Canyon Express pipeline project in the Gulf Mexico set a new depth record when gas started flowing from the Marathon's Campden Hills field, in 7,200 ft of water, during October 2002. The subsea project is also the first of its kind to develop three different fields, each operated by a different company, by a common multiphase gathering system.

The sharing of a common subsea gathering system was made possible by the use of multiphase meters to allow the fluids entering the system to be allocated to particular fields for fiscal and taxation purposes. The development of such meters was the focus of an enormous amount of R&D during the 1990s and the technology presents many challenges due to the unpredictable nature of the flow regimes.

A significant number of subsea multiphase meters were installed in the North Sea for well test purposes (where 5% accuracy is acceptable), but the acceptance of this technology for flow allocation by the US Minerals Management Service (MMS) is a major step forward, showing considerable confidence in the latest generation of instruments.

The Canyon Express project also develops the TotalFinaElf-operated Aconcagua field, in 7,000 ft of water, and the BP-operated Kings Peak field in over 6,200 ft of water. Peak gas production from the three fields will rise to 500mn cf/d. Dual 12-inch diameter pipelines connect the satellite wells to a shallow-water host platform on East Main Pass block 261, with flow assurance for this 105-km step-out assisted by round-trip pigging.

Subsea booster systems

Subsea booster systems have been the subject of considerable research on this side of the Atlantic, with some R&D funded under Demo-2000 in Norway. The use of subsea booster pumps allows longer tie-backs, but can also be used to enhance production during the later years of field life. Much of the recent R&D has focused on pumps that can handle elevated gas fractions.

One major project initiated under the Demo-2000 programme was a compact and lightweight subsea multiphase pump module (SMPM) suitable for 1,500-metre water depths. The project was funded by Kvaerner Eureka, Norsk Hydro and Demo-2000, with the SMPM specifically designed to boost the wellstream from the Sognefjord reservoir.

A prototype was tested at K-Lab at Kårstø in 1Q2002 whilst it was submerged in a 12-metre high water-filled tank and connected to a hydrocarbon 'reservoir' that allowed circulation and adjustment of the gas content. Some tests were carried out at very high gas/liquid fractions to ensure that the system could act as a wet gas compressor as well as a multiphase pump.

Framo Engineering has up until now been regarded as the market leader in this field. The company has installed a number of subsea booster pumps in regions as far apart as the North Sea, South China Sea and West Africa. Nils Vågen of Framo Engineering reports that: 'All of our pumps operating on the seabed have been operated with 100% availability'. He adds that Framo subsea booster pumps have now accumulated more than 250,000 hours of successful operating experience.

All subsea booster pumps have so far been incorporated in subsea manifolds at the initial design stage, but there are now proposals to retrofit pumps to existing subsea wells in order to boost tail end production. This task has been made possible by the development of a wellhead insert system by Subsea 7, in partnership with DES Operations. The multiple application re-injection system (MARS) may be installed on new or existing wellheads by simply removing the tree-cap and replacing it with the insert assembly.

The function of the insert is to divert the well flow from the production bore to externally mounted equipment for processing or pumping, then returning the product back to the tree where it follows the conventional flow-path to the pipeline. In addition to wellhead pumping, the system can also be used for flow metering, subsea processing, chemical injection and extended well testing.

Advanced technology for Troll

The Troll field is best known as Europe's largest gas field, with gas produced by the giant Troll A platform. However, the field is less well known as Norway's largest oil producer, achieving a record output of over 440,000 b/d during 2002. The field has also provided a test bed for advanced subsea solutions, including subsea processing and subsea multi-lateral wells.

It was not until the advent of advanced horizontal drilling technology that it became possible to exploit the oil-bearing layers between Troll's gas cap and the underlying aquifer, which can be as thin as just 10 metres in places. The Troll B and Troll C floating production units (FPUs) were installed by Norsk Hydro to produce this oil, with each FPU connected to subsea wells.

An innovative subsea system called Troll Pilot was installed as part of the overall scheme – it is reportedly the most advanced subsea processing system in service at the present time. The purpose of Troll Pilot is to remove bulk-water from the oil stream and to re-inject this water back into the reservoir while allowing the oil stream to pass on to the Troll C FPU.

The multiple benefits of this system include a reduction in fluid volumes flowing to the FPU (leading to reduced separator capacity and lower topside weight); the maintenance of reservoir pressure by water injection; and an environmentally friendly method for the disposal of produced water. Unfortunately the unit suffered from teething problems shortly after it came onstream and a $15mn, eight-month repair and upgrade project was required to rectify these problems, which completed by the end of August 2001.

Speaking about recent experience with the system, a spokesperson for Norsk Hydro said: 'Troll Pilot is a success and has been running for a year without problems. It's highly recommended when there is a lot of water.'

Oil recovery from Troll has also been enhanced by the use of multi-lateral wells, with Norsk Hydro achieving a world-first during August 2002 with the installation of a tri-lateral well from a semi-submersible drilling rig. Sperry-Sun, part of Halliburton Energy Services, installed the tri-lateral. This solution will make it possible to produce an additional 1.5mn barrels of oil. Prior to this project Norsk Hydro had installed 16 two-branch multi-lateral wells in the field. The multi-lateral wells have side branches that can tap small pockets of oil and gas that could otherwise be isolated from the main well bore. In addition to allowing the operator to target these small pockets of oil, the multi-lateral wells also produce more oil due to the increased number of conduits.

There is a more general concern within the industry, however, about the low recovery of oil from subsea production systems that arises because of the high cost of well intervention. Such operations are needed for data acquisition, remedial work, stimulation, zonal flow control and general maintenance. The high cost of intervention on subsea wells is a deterrent, with the consequence that oil recovery from subsea wells is currently 8% below that of wells on platforms.

Subsea light-well intervention

These costs could be reduced by performing intervention by dynamically positioned (DP) mono-hull vessels, or small-scale semi-submersibles. The benefits of these 'light-well services' are not simply that the light vessels are less costly to charter than drilling rigs, but also that the charter time is reduced through more rapid transit and shorter set-up time once the vessel arrives at the well site.

There is enormous potential demand for light-well services, with around 750 subsea wells in the North Sea and a further 750 subsea wells installed elsewhere in the world. Service companies entering this growing market can build on the experience gained by the monohull *Seawell* using a subsea wireline unit, and by the semi-submersible *Uncle John*. The newly built *Q4000* can, meanwhile, offer intervention services to ultra-deepwater fields.

There was consolidation amongst the subsea well service providers during 2002 when Well Ops, a wholly-owned subsidiary of Cal Dive that operates the *Uncle John*, acquired the Coflexip Subsea Well Operations Business. The Coflexip business unit operates the *Seawell*, a 111-metre DP vessel that has carried out intervention and abandonment services for more than 400 North Sea wells since she came into operation in 1987.

Well Ops also operates the *Q4000*, built at a cost of $180mn and delivered in April 2002. It has been described as the first semi-submersible vessel designed to perform construction and well intervention tasks in water as deep as 10,000 ft. Features include a tower capable of lifting 600 tonnes, a large deck space (15,000 sq ft), significant deck load capacity (3,400 tonnes) and a high transit speed (12 knots).

The *Q4000*'s first subsea well intervention project was performed during July 2002 for Petrobras America in 500 ft of water in the Gulf of Mexico. This project involved the final abandonment of a temporarily plugged exploration well and was performed through a small-bore (5.125-inch) mono-bore intervention riser.

A riserless light-well intervention service (RLWI) will meanwhile become available on the Norwegian Shelf following a cooperation agreement between FMC Energy Systems, Halliburton and Prosafe during August 2002. This service will be delivered from Prosafe Offshore's large fleet of support vessels.

A subsea wireline unit has been built for this RLWI service by FMC Kongsberg Subsea as the result of a joint-industry project started in 1997, which also involved Statoil, Shell and Halliburton. The prototype was being tested during 4Q2002 at the Coast Centre Base – a newly established quayside facility at Ågotnes, outside Bergen.

The RLWI service will initially be performed by Prosafe Offshore's *MSV Regalia* that was being upgraded for well intervention work at the end of 2002 and should re-enter service by the end 1Q2003. She is then contracted to undertake intervention work on between four and 12 subsea wells for Statoil.

Dry-tree solutions

Despite the advances in subsea production systems there are many instances in which a dry-tree solution needs to be adopted. Fixed platforms and compliant towers can support Xmas trees above the surface in significant water depth – the Texaco Petronius compliant tower set a record of 1,754 ft water depth for a fixed structure when it was installed in Gulf of Mexico during May 2000.

Beyond those depths the choice currently lies between tension leg platforms (TLPs) and spars, although even more innovative solutions, such as dry-tree floating, production, storage and offloading (FPSO) vessels, are on the horizon.

Dominion's Devils Tower development is the deepest spar project to date, with a water depth of 5,610 ft, while Conoco's Magnolia will be the deepest TLP when it is installed in a water depth of 4,700 ft. However, engineers are already studying new generations of facilities for depths up to 10,000 ft. The reduction in weight of components linking surface facilities to the seabed, such as risers, mooring lines and tethers, are a major focus of the R&D work for these projects.

Deepwater spar technology

Three generations of spar technology have so far been adopted in the Gulf of Mexico since the first spar was first installed on the Neptune field by the then Oryx Energy during 1996. The Neptune spar consists of a cylindrical steel hull measuring 72 ft in diameter and 705 ft high, with free-standing risers held upright by buoyancy modules within a central moonpool.

This basic spar design was followed by a truss spar that had open steelwork in the lower part of the hull. Kerr-McGee's Boomvang was the first truss spar – it came onstream during June 2002 in 3,600 ft of water. A similar design was used for the associated Nansen field. The open truss design was said to enhance the spar's stability while reducing size and cost.

In August 2002 Kerr-McGee decided to adopted a third generation spar design for development of the Red Hawk field in 5,300 ft of water. The Red Hawk spar, which is to be built by

Technip Offshore, will measure 64 ft in diameter and 480 ft high. The spar design consists of a central steel tube surrounded by six similar tubes, with all seven of these 20-ft diameter tubes connected in a bundle by structural steel.

The future could see spars deployed in even greater depths, up to say 10,000 ft, as the result of a conceptual engineering study which was carried out by Halliburton KBR for development of a large high pressure/high temperature (HP/HT) field in the Gulf of Mexico. The R&D study was sponsored and funded by DeepStar, a programme that is supported by 15 oil company participants and about 50 other companies. Three options for the mooring system and riser design were investigated for this study:

- steel mooring with steel risers,
- polyester mooring with steel risers, and
- polyester mooring with composite risers.

Synthetic, polyester mooring lines have been used for several years in Brazil for permanent deepwater mooring but this technology has only recently been approved for use in the Gulf of Mexico. The MMS announced its first approval for permanent use of such moorings for a deepwater development on 7 November 2002. The approval came as part of a preliminary review of BP's Deepwater Operations Plan (DWOP) for the Mad Dog project in 4,420 ft of water, another project that involves a truss spar.

MMS says that the high strength polyester fibres provide an equivalent or greater level of protection to steel wire rope systems while reducing the vertical loads on the spar hull. The Mad Dog truss spar will be held on location by an 11-line polyester taut-leg mooring configuration.

Carbon fibre composite materials are also seen as having great potential for deepwater risers and tendons for TLPs in ultra-deepwater projects. This material is said to provide many desirable properties, including high specific strength and stiffness, lightweight, corrosion resistance, high thermal insulation and excellent fatigue resistance.

Deepwater composites

During June 2002 Conoco and Aker Kvaerner announced the setting up of a new joint-venture company, called DeepWater Composites, to manufacture and market composite products for deepwater oil and gas projects. The companies had previously cooperated under a technology alliance, since 1995, to develop, test and qualify two carbon fibre composite products – one for riser and the other for tether applications in deepwater.

As a result of this alliance the world's first composite riser, called CompRiser™, was successfully tested in a live drilling operation during 2001, when it replaced a high pressure titanium riser joint in a drilling string that was on the Statoil-operated Heidrun TLP platform in the Norwegian sector of the North Sea. CompRiser™ is made of carbon fibres and epoxy resin, and weighs around half the weight of its steel equivalent. After the first drilling cycle the riser was thoroughly inspected and pressure tested by DNV.

The use of composite tendons was apparently considered during conceptual design of the Conoco-operated Magnolia TLP that is to be located in 4,700 ft of water in the Gulf of Mexico. But, in the event, it was decided to employ stepped tendons and other features of ABB's proprietary extended tension leg platform (ELTP) system. However, composites will no doubt start to play an increasing role as operators consider even deeper TLP applications.

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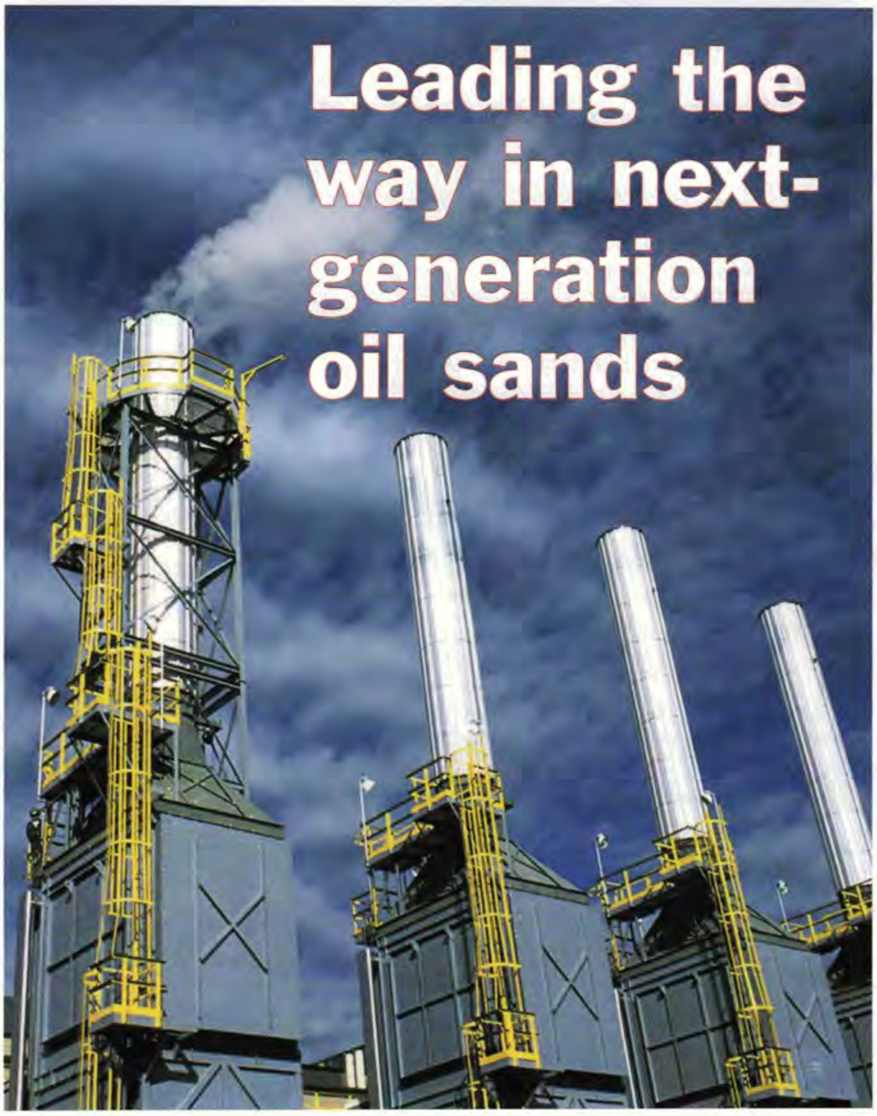
Leading the way in next-generation oil sands



Holding more oil resources than Saudi Arabia, the oil sands of northern Alberta, Canada, are set to become the focus of the North American energy industry in the next two decades, writes *Joanna Farley*.* Although the oil industry has known of the tremendous potential of the Athabasca oil sands for decades, it is today's new technological advances that are making this resource more attractive than ever before. Petro-Canada is a leader in the oil sands arena and in the application of environmentally-sustainable extraction methods. It has recently brought onstream its MacKay River project, a 30,000 b/d thermal oil sands facility that provides a benchmark for similar schemes.

Above: Four steam generators

Oil sands reservoirs contain bitumen, a heavy, tar-like oil, trapped between grains of sand. Surface mining is the traditional oil sands extraction method, but the majority of reserves are buried too deeply to be economically exploited this way. In-situ (Latin for 'in place') recovery methods have more recently been developed whereby steam is injected into the reservoir to heat the bitumen, allowing it to flow and be extracted. This bitumen must then be upgraded into light synthetic crude oil before it can be refined into petroleum products.

Supplies of Canadian light conventional oil are rapidly declining and many companies are focusing on developing oil sands properties in northern Alberta, where recoverable reserves are currently estimated at over 300bn barrels of bitumen (total resources are estimated at a staggering 2tn barrels of bitumen). The projected growth in oil sands development will likely impact the North American market significantly in the coming years, through a predicted oversupply of raw bitumen from new oil sands leases and, from those properties refining their bitumen on-site, a potential over-supply of synthetic light crude.

At present very few refineries have the capability to process either bitumen or synthetic light crude, resulting in a lack of purchasers for these resources. To support these developments a pipeline transportation system capable of carrying upwards of 500,000 barrels of bitumen from the oil sands regions may be necessary within the next few years, while refineries may need to be upgraded or built to process synthetic crude and bitumen.

Leading the field

Petro-Canada plans to address these challenges while establishing the company as a leading oil sands producer and refiner in the next 10 years by building a fully integrated system to move bitumen all the way from the reservoir to the gas tank. This will be done through a multi-phased strategy that confirms oil sands as a major core business for the company.

The first phase is the development of oil sands leases, including the newly operating MacKay River project, followed by Meadow Creek, a 80,000 b/d project slated for first oil in 2007. Phase two of the strategy will see Petro-Canada's Edmonton refinery converted to process bitumen, with the first stage of the refinery conversion project planned to enable the refinery to upgrade 85,000 b/d of bitumen by 2007. A potential second stage could see the refinery capable of upgrading a total of 170,000 b/d. The synthetic crude oil will then be refined into a full suite of petroleum products, much of which will be distributed through Petro-Canada's retail gasoline network.

The MacKay River project, located 60 km northwest of Fort McMurray, Alberta, covers over 122 sq km of land and is 100% owned and operated by Petro-Canada. There are up to 300mn barrels of recoverable bitumen in the current MacKay River development area, where the daily yield will be 30,000 b/d over 25 years once full production is achieved in 2003. The project consists of well pads and facilities, a central processing plant and a short insulated lateral pipeline connecting to Enbridge's Athabasca terminal. The oil is then diluted and shipped to Hardisty, Alberta, where it is made available for heavy oil purchasers.

A Mackay River slant production wellhead. A total of 25 wells will be drilled over the field's 25-year lifespan – half of them producers like this one and half injector wells.

Oil sand history

The oil sands have a long history of human use. Aboriginal people originally used the tar mixed with spruce gum as a sealant for their canoes and in the early 20th century the tar was used to pave roads in Alberta. Petro-Canada became involved in the oil sands in 1978 when Syncrude Canada, a consortium of oil companies and the federal and provincial governments, opened a mining and upgrading project to produce high-quality synthetic crude oil. Using surface mining techniques Syncrude was, and still is, the largest producer of synthetic crude oil in Canada, contributing over 10% of Canada's oil supply.

In 1979 Petro-Canada was among the first to experiment with horizontal steam injection pair wells, which were drilled into the banks of the Athabasca River. The bitumen extraction attempt was successful, but it was abandoned when oil prices dropped sharply, eliminating funding for experimental projects.

About this time the first commercial in-situ thermal extraction technique, cyclic steam stimulation, was developed by Imperial Oil. In cyclic steam – known as 'huff and puff' – one vertical well is drilled into the reservoir to inject steam and later extract the heated bitumen. During the process huge amounts of steam are injected under high pressure down the well, cracking and entering the reservoir. The steam is then left to heat the bitumen for a few weeks, after which bitumen is extracted for several months. The process is repeated once the reservoir cools.

As unstable oil prices continued, Petro-Canada decreased its share in Syncrude and, looking for more economical ways to recover bitumen, joined the Underground Test Facility (UTF), operated by the provincial government's Alberta Oil Sands Technology and Research Authority (AOSTRA). At the UTF steam-assisted gravity drainage (SAGD) was first tested. Developed by Dr Roger Butler of the University of Calgary in Alberta, the SAGD process uses pairs of long horizontal wells to continuously inject steam and produce bitumen. After several years of development by the UFT consortium, which included the adoption of twin well pairs drilled in a parallel under/over configuration and using slant drilling rigs, SAGD was deemed economically viable. In the mid-1990s several companies began SAGD pilot projects while Petro-Canada began delineation at MacKay River, a land lease adjacent to the UTF project.

Record breaking facility

MacKay River is the largest SAGD facility built to date. Pairs of horizontal wells are drilled from central pads, fanning out into the reservoir underground. Steam is then injected through the upper well, continuously heating the bitumen. The mobile bitumen and condensed steam drains by gravity to the lower well. Down hole pressure created by the steam then allows the bitumen and water to flow to the surface.

SAGD has the best steam to oil ratio of current oil sands in-situ methods and is much more efficient than other recovery techniques. SAGD has been proven to recover 60% to 80% of the bitumen in place, versus an average of 30% with cyclic steam.

Pipeline network on one of the two current production pads. The pads are located about half a mile from the central plant. MacKay River's 25 initial well pairs are grouped on two such production pads. Pipes carry steam from the central generators to the pads; different pipes carry produced bitumen, gas and fluids back to the plant for separation and processing.

Environmental challenges

Oil sands development presents unique environmental challenges. Traditionally, oil sands were mined from the surface, disrupting vast amounts of land and leaving a large 'environmental footprint'. In addition, when separating bitumen from the oil sands, significant amounts of water are consumed and large quantities of greenhouse gases produced. Although SAGD technology is more environmentally acceptable in many respects than other extraction methods, it still produces greenhouse gases and consumes water. Petro-Canada is taking steps to decrease both the amount of emissions produced and water used in the SAGD process at MacKay River.

To reduce greenhouse gas emissions, a 165-MW cogeneration plant will power the MacKay River project by producing electricity and heat energy from natural gas. Cogeneration plants are highly efficient and, by using the waste heat produced as an energy supply to generate steam, MacKay River will be able to cut emissions by up to 50%. The cogeneration plant, being built by TransCanada Energy, will be operational in 2003. It will fully power MacKay River, with excess electricity being sent on to Alberta's power grid.

Using a closed-loop water recycling programme Petro-Canada has reduced consumption of local water resources. Known as Zero Liquid Discharge, more than 90% of the water used at MacKay River will be from recycled sources. Large amounts of water are heated and sent via pipelines to manifolds that control the flow of steam into the injection wells. Once injected, the steam loses its heat, condenses back into water and returns to surface with oil from the production well. This water is then separated from the oil, treated and reused to produce more steam. Even the most contaminated water, which is often sent to disposal wells at other operations, will be recovered by a leading-edge water treatment system.

As SAGD uses central well pads and horizontal drilling there is far less surface environmental impact than in oil sands mining. The horizontal well pairs used at MacKay run up to 1 km underground, which means that less than 20% of the entire development area will be disturbed on the surface. Top soil from construction activities has been retained and will be reused during remediation of the site. In addition, drilling waste was minimised and then mixed with wood chips from site clearing to form a rich compost.

Petro-Canada currently has 25 well pairs in operation. As wells deplete, new ones will be drilled and the site reclaimed on an ongoing basis. The company consults with local Aboriginal communities to determine how best to develop and later reclaim the land. Petro-Canada is also involved in a wide range of local programmes and organisations that monitor and reduce environmental damage in Northern Alberta.

Although recent advances in oil sands technology have reduced projects' energy consumption, the environmental challenges are still significant in the oil sands industry. In December 2002 Canada ratified the Kyoto Accord, dedicating Canada to the reduction of greenhouse gases. Although the Government of Canada has indicated its support for further oil sands development, the industry and the government are still working on solutions that will capture the tremendous economic value of the oil sands while continuing to reduce emissions and protect the environment.

** Joanna Farley has recently completed an internship as a Communications Assistant at Petro-Canada as part of her Communications Degree at the University of Calgary.*

The end of production targets?

In recent times, markets have focused on production targets and delivery as a key measure of an upstream company's success. Failure to meet targets and downgrades of future estimates have been met with reductions in share price often out of all proportion with the potential impact on companies' earnings. Here, *David Morrison* and *Matthieu Castellani* of Wood Mackenzie suggest that there should now be a shift away from volume to value growth.

Targets affect the strategies and behaviours of companies and we believe that excessive focus on production targets in the upstream business is interfering with efficient portfolio management. Companies are encouraged to keep inefficient assets to maximise volumes. As a result, assets do not end up in the hands of their 'natural owners' leading to sub-optimal performance in the industry as a whole.

The relentless pursuit of volumes may also push the industry into taking inappropriate development decisions, accepting tough terms and thin margins. Finally, the perceived need to show a rising production profile has encouraged 'strategic' acquisitions at premium prices, which have destroyed value in the acquiring company.

For these reasons, we at Wood Mackenzie believe that the excessive focus on production growth targets has adversely affected total shareholder returns. The industry and the markets need to shift the emphasis away from volume to value.

Ambitious growth targets

Companies have, to an extent, created the problem themselves by the ambitious growth propositions they have made to shareholders. Expectations have been unrealistic – most companies will not be able to grow production at 3% to 7% annually through organic growth. Even to achieve relatively modest production growth while maintaining a constant R/P (reserves/production) ratio requires a good underlying reserve replacement performance. For example, a 3%/y production growth would require a reserve replacement performance of around 135% to 140%, something that few companies have been able to achieve in recent years.

Production targets are popular because they are simple to measure, transparent and not open to manipulation. They are also independent of oil and gas prices and, therefore, show underlying growth irrespective of the state of the commodity price cycle. However, production growth targets are only a proxy for value growth and by concentrating on this measure in exclusion there is a danger that behaviours will be encouraged that are at odds with value growth considerations.

This focus on production growth is also coming at a time when it is more difficult for the industry to find profitable growth opportunities. Exploration trends for some are disappointing; many of the large conventional plays are mature or declining; competition is fierce and many companies now have very strong balance sheets and financial capability. The internationalisation of some national oil companies is producing new and well-funded competitors. However, politics are slowing progress in some regions – such as Brazil, Venezuela, Middle East, Mexico, Russia, Arctic National Wildlife Reserve (ANWR) – and the political risks of investing in areas such as the Middle East and Russia are high.

In this highly competitive environment it is important that the measures used by the market do not encourage companies to focus on production growth at the expense of value.

New yardsticks

The key question that any measure should be seeking to answer is: 'Are oil and gas companies creating value?' Supplementary queries include: 'Who? Where? How? How much?'

Cash flow and unit earnings tell us about the current state of the companies but not about their growth potential. RoCE (return on capital employed) is also a current measure, being largely dictated by the companies' legacy portfolios and decisions taken in the past with regards to write-downs. Because a company currently has a high RoCE does not necessarily mean that its recent and future investment decisions are going to create more value than those in a company with a lower RoCE. In fact, a period of heavy investment activity, which will lead to future value creation, will act to depress RoCE as the impact of this capital spending is likely to be delayed due to the long lead-times of many upstream projects.

At Wood Mackenzie we rely heavily on NAV (net asset value) analysis of future project cash flows when dealing with valuation issues. This is, of course, standard practice within the industry when evaluating projects internally. Most traditional accounting metrics look back, not forward. NAVs offer a view on the value of individual assets or of a business based on future estimations or assumptions expressed in current terms. In looking at performance, whether as a manager or an investor, it is the future that counts. While the absolute NAV results are greatly affected by critical inputs such as commodity prices and the choice of discount rate itself, comparative rankings between companies offer a good guide to relative rankings.

A greater use of NAV analysis is, we believe, one way to answer the key question 'Which companies are creating value for their shareholders?' For example, a NAV analysis of the cash flow (actual and predicted) of fields discovered in the past five years when compared to a company's exploration spend would clearly show whether value was being created in this area.

Where now?

Transparency will be critical. As Sir Henri Deterding said in 1934: 'Our Royal Dutch-Shell operations would never have succeeded as they did if we had tried to keep any part of our general working policy a secret… there is no better way of winning the confidence of your shareholders than to make them understand as you go along every possible detail of just how any business, into which they have put their money, has been run.'

Two key questions remain. What are the best measures of performance? And, for these measures, what targets should companies promise the markets? The first will evolve from debate between the industry, analysts and investors and also from industry leadership. The answer to the second will require companies to have a very clear view, *inter alia*, of their current portfolio, of the key value drivers and of the competitive environment.

A number of companies are considering changes to their strategy and the way in which they will characterise their performance. Now is the time for all interested parties to engage in the debate.

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Swedish fabricator Emtunga has a number of living quarters fabrication contracts booked for projects in the Caspian and its first in the Gulf of Mexico (see table), clearly showing that its market is no longer confined to the North Sea. Pictured is one of two living quarters barges for Agip-KCO, leaving Sweden in September 2002 for towing to the Caspian Sea via the Russian Volga/Don Canal system.

Photo: Emtunga

Facing the challenge

The Far East, in particular South Korea, emerged as the dominant force in the global fabrication market by offering reduced cost bases for projects when the European sector began its downturn in the mid-1990s. The challenge for the European sector is to wrestle some of these gains back by emphasising its greater technology offering and demonstrating that it can complete jobs more efficiently. There are signs that Europe's fabricators are heading in this direction with the major Bonga and Kizomba contract awards to Amec and Heerema. *Kim Jackson* reports on how Europe's fabricators are faring in today's increasingly competitive market.

The European fabrication sector is continuing to struggle to cope with excess capacity and a lack of large platform construction contracts as offshore operators are increasingly bringing new projects onstream via subsea completions. Many yards are having to diversify their operations, target new markets and embrace new contracting strategies in order to stay in business.

Some have chosen to move away from EPIC-structured contracting in a bid to avoid the risks associated with supplying production units, mainly FPSOs, at budgeted prices. Halliburton led the way with its announcement in July last year that its Kellogg, Brown and Root (KBR) subsidiary would no longer take on EPIC contracts due to their unacceptable risk-reward ratio. Other contractors, while not moving completely away from EPIC contracting, are being more choosy about who they do business with, focusing attention on existing clients where they are assured their contracts are strong.

Others are looking further afield, exporting their North Sea skills. For example, Amec Offshore Services secured a major contract in August 2001, teaming up with alliance partner Fluor Daniel and Hyundai of South Korea, to work on ExxonMobil's Kizomba oil production vessel destined for operation offshore Angola, West Africa. Amec is providing its North Sea expertise to the project. The 300,000-tonne hull and 20,000-tonne topsides are being fabricated at Hyundai's Ulsan yard in South Korea. Although the project will not directly generate a large number of UK jobs, it is the kind of contract that the UK Government has been encouraging as it generates valuable export trade.

Amec is also acting as project manager for the engineering, fabrication and installation of the 17,000-tonne topsides for the 300,000-tonne Bonga FPSO. Its Wallsend yard in Tyneside fabricated two of the modules, the others under construction by Heerema in Hartlepool and Zwijindrecht in Holland, with three small units fabricated in Nigeria. The hull arrived at Tyneside in November 2002. Due to be installed on the deepwater field offshore Nigeria in summer 2003, Bonga has a storage capacity of 2mn barrels of oil and will be capable of producing 225,000 b/d of oil and exporting 150mn cf/d of gas. First oil is expected in 1Q2004.

UK hit hard

The UK fabrication sector has been hit hard in recent years, with a number of yards closing, including Ardersier, Methil and UiE Clydebank, and KBR Caledonia's facility at Nigg remaining on inspection, repair and maintenance (IRM). The one bright spot on the horizon is the pending tender for EnCana's Buzzard field, the biggest discovery on the UK Continental Shelf for over 10 years. According to Neil Bruce,

Photo: Intermare

Intermare reports that at present there are not many fabrication tenders pending in its traditional markets of the Mediterranean Sea, North Sea and West Africa. However, it is heavily involved in supporting parent company Saipem on several EPIC projects in both shallow and deepwater areas. Pictured is an offshore drilling rig being revamped and upgraded by Intermare on behalf of Saipem.

Vice Chairman of the UK Offshore Contractors' Association (OCA), the project 'presents great opportunities for UK fabricators in particular and will attract significant interest as it represents a great financial boost to the winner or winners of the bidding process.'

Bruce also confirms that the UK fabrication sector 'must embrace new contracting practices and enter new markets' in order to stay competitive. 'The only way to reverse the current global trend is to provide complete solutions to clients by combining the services of project management and engineering of projects in order to add value. Competing financially is untenable due to the cost bases currently offered by the Far East yards. In terms of skills, experience and capabilities the UK and European markets are world class, but need to provide tailored solutions to customers by providing the entire package.'

According to Bruce the renewable energy market is emerging as 'potentially lucrative'. The development of wind turbines in particular is creating great interest as Scotland possesses

Operator/Contractor	Field*	Work	Delivery
UNITED KINGDOM:			
Amec Offshore Services			
ExxonMobil	Kizomba, offshore Angola	partnering Fluor Daniel of US and Hyundai of South Korea; oil production vessel to be built in South Korea	2003
Shell	Bonga, offshore Nigeria	£300mn contract; two modules and topsides for FPSO	–
BP	Clair Phase 1	£50mn contract for main deck fabrication and integration work	2004
Burntisland Fabrications			
BP	Schiehallion	24-man accommodation module	–
Consafe			
TotalFinaElf	Dunbar	six-storey complex of prefabricated accommodation modules	–
Heerema Hartlepool			
Shell	Bonga, offshore Nigeria	4,500-tonne process module	1Q2003
BP	Clair, Atlantic Frontier	4,500-tonne drilling module	mid-2004
KBR Caledonia			
Nigg (formerly Barmac)		inspection, repair and maintenance (IRM)	
SLP Engineering			
Shell	Goldeneye	1,200-tonne topsides	Jun 2003
Petro Pars	South Pars, Iran	project management, engineering and procurement services for three gas platform jackets	mid-2003
FRANCE:			
Bouygues Offshore			
ExxonMobil	Erha, West Africa	2.2mn barrel storage capacity Erha FPSO	–
NORWAY:			
ABB			
Statoil	Kvitebjørn	10,500-tonne PDQ	Mar 2003
Statoil	Sigyn	tie-in to Sleipner A platform	3Q2003
PPCon	Ekofisk	process capacity upgrade, approx 800 tonne	3Q2004
Statoil	Karsto/Draupner	$35mn, five-year contract for maintenance and modification of the Karstø gas treatment plant and Draupner platforms	
Norsk Hydro	Visund	$80mn contract for 670-tonne and 300-tonne modules – one contains equipment to boost gas injection rate and increase oil production; the other will allow gas export from platform	2005
Aker Stord			
Phillips Petroleum	Maureen	ongoing decommissioning contract pushed forward from cleaning to dismantling	Nov 2001+
Norsk Hydro	Fram West	800-tonne module on Troll C	May 2003
Norsk Hydro	Grane	5,500-tonne drilling module	May 2003
Statoil	Kristin	NKr5bn contract; floating production platform	2004/5
Aker Verdal			
Norsk Hydro	Grane	17,500-tonne steel jacket	Mar 2003
Shell	Goldeneye	jacket	–
BP	Clair Phase 1	steel jacket	2004
Heerema Tønsberg			
BP	Valhall (flank)	NKr1bn EPIC contract for wellhead platform; option for second wellhead platform	3Q2003
Kvaerner Oil and Gas			
Norsk Hydro	Grane	NKr500mn contract; 5,500-tonne power generation and living quarters	May 2003
Petrobras	Albacora Leste, Campos Basin	topsides processing modules	2003
ITALY:			
Intermare Sarda*			
Saipem	offshore drilling rig	revamping and upgrade of modularised rig	–
Saipem/Agip	Sabratha	22,000-tonne jacket	2004
AENR Nigeria	Okpoho, Nigeria	management, procurement and pre-fabrication activities for wellhead platform in consortium with Saipem Nigeria and local partner	2003
		* Also involved in management, procurement and sub-assemblies pre-fabrication in support as a technical partner at Saipem's Port Harcourt, Nigeria, yard on several Nigerian projects	
Saibos			
ExxonMobil	Yoho-Awawa	production platform	–

Current workload at some European fabrication yards ** North Sea unless otherwise indicated*

Operator/Contractor	Field*	Work	Delivery
THE NETHERLANDS:			
Grootint			
Shell	Bonga, offshore Nigeria	6,500-tonne process module	1Q2003
ExxonMobil	Kizomba A	12,000-tonne topsides	2003
Heerema Havenbedrijf			
BP	Valhall (flank)	2,000-tonne jacket	3Q2003
NAM	L5	300-tonne compression module	2Q2003
HGB Offshore			
Conoco	CMS III	1,000-tonne compression module	Jun 2003
Clyde Petroleum	Q/4C	1,200-tonne platform jacket, piles and 2,200-tonne topsides	Jun 2003
SPAIN:			
Dragados Offshore			
Statoil	Kristin	NKr300mn contract for 4,300-tonne riser balcony and 270-tonne flare boom	Mar 2004
ChevronTexaco/Stolt	Sanha	DPP jacket/WPA jacket	Jun/Aug 2003
Pemex	Cantarell, Mexico	11,000-tonne production/compression deck	Aug 2003
Izar			
Exmar Offshore	Aquitaine, Med'n Sea, offshore Libya	900,000 barrel capacity FPSO	Jan 2003
SWEDEN:			
Emtunga			
Prosafe	Safe Scandinavia	500-tonne living quarters extension for 256 men	2003
Agip-KCO	Kashagan, Caspian	two 130-men living quarter barges, incl all utilities	2003
AIOC	Chirag FFD Ph1, Caspian	1,200-tonne living quarters for 130 men	2003
Statoil	Kristin	1,700-tonne living quarters for 112 men	2004
BP	Mad Dog, Gulf of Mexico	1,000-tonne living quarters for 130 men	2004
AIOC	Chirag FFD Ph2, Caspian	two 1,200-tonne living quarters for 130 men	2004/2005

Current workload at some European fabrication yards ** North Sea unless otherwise indicated*

40% of Europe's wind capacity. However, Bruce warns that 'UK fabricators will face stiff challenges in securing the work from established European companies that have already secured high profile contracts in the wind-rich Scandinavian countries.'

UK fabricators are also looking to diversify from the traditional central and northern North Sea market, to target smaller southern sector contracts and developments in the Gulf of Mexico and West Africa. This trend is being followed elsewhere in Europe, with a number of fabricators reporting that they are also looking to secure onshore oil and gas construction work as well as civil engineering contracts for the fabrication of bridges, quays etc.

However, some such as Aker Kvaerner, continue to focus specifically on oil and gas fabrication. The company believes that it needs to maximise its focus and efforts of both management and staff on the oil and gas sector in order to remain competitive, focus that is difficult to achieve when also looking to enter new markets. The company's Aker Verdal yard focuses on heavy structural work, such as jackets, decks and floater hulls, while sister company Aker Stord has moved from general steel fabrication to specialise on the construction of topsides, hook-up and commissioning. According to Group President Helge Lund when presenting the company's interim results last year, 'the North Sea and Norwegian sectors are still attractive, but markets will change, with smaller projects and more complex tail-end work. Maintenance and modification operations are a better arena with better profits.' He also said that he hoped new large projects in northwest Europe would come forward as oil companies return to frontier exploration.

Photo: Emtunga

Offshore installation of the 120-man living quarters for Esso Norge's Ringhørne development in the North Sea, fabricated by Emtunga, delivered to Heerema Tonsberg in 2001.

Norwegian prospects

The Norwegian fabrication sector has, and continues, to fare slightly better than in the UK. In the past, the Norwegian Government has 'rationed' project approvals in order to ensure that its development programme and fiscal changes have tied in with the capacity of its yards, with only a minimum of work permitted to go abroad. This means that most of the Norwegian yards have, to date, had a reasonably full order book. However, although Norwegian prospects continue to be good in the short-term there are no longer enough projects for the government to continue its rationing policy. Many expect the Norwegian fabrication sector to follow the pattern set by the UK over the past decade with yards closing as overcapacity takes hold. Up to 6,000 job losses, including engineering personnel, are forecast to be lost by 2005/2006.

As in the UK, some Norwegian fabricators are looking to diversify away from their domestic base, bidding for projects in the Gulf of Mexico and West Africa. For example, ABB – which in 2000 acquired the oil and gas activities and fabrication facilities of Umoe in a bid to target large turnkey projects – is currently working on the surface wellhead platform for the Kizomba project offshore Angola. Aker, too, is targeting the Gulf of Mexico, West Africa and Asia-Pacific markets, as well as offshore Newfoundland.

Rising Russian production targets export markets

Of all the major oil producing countries one would have expected Russia to have the wherewithal to avoid becoming a commodity-led economy. And yet the International Monetary Fund (IMF) warns that Russia is becoming too dependent on oil revenues and that the government has so far been unsuccessful in steering away the economy toward non-commodity sectors. Indeed, while investment in the oil sector has increased significantly, investment in the manufacturing sector is very low and is even showing signs of decline.* *Mojgan Djamarani* reports.

Russia's financial crisis of 1998 and the subsequent devaluation of the rouble reduced the cost of oil production and the high oil prices boosted revenues without new investments or production increases. The financial position of the Russian oil companies has also been strengthened by the gradual rise of domestic oil prices and these companies have now begun to make substantial investments in upstream exploration and development as well as downstream operations.

In 2001 Russia produced 348mn tonnes of oil and became the world's second largest exporter with an average export rate of 4.91mn b/d. In 2002 production reached 379.63mn tonnes and exports 5.17mnb/d – in February 2002 the country even briefly overtook Saudi Arabia to become the world's largest oil producer.

This year the government plans to meet an output level of 390mn tonnes, rising to 424mn tonnes by 2005. In the period 2001–2005 the Economy Ministry is forecasting oil exports will increase by between 20% and 33%. With the domestic demand for oil largely expected to remain stable, any new increases in production will be directed towards exports.

All Russian oil companies, with the exception of Lukoil, registered impressive growth in production in 2002 (see **Table 1**). Sibneft, which has only one-third of Lukoil's crude reserves, increased production by 28%; Yukos by 20% and Surgutneftegaz by 11.7% over 2001. Lukoil only registered a 1.5% increase, the company attributing its performance to the short-term consequences of its new business strategy to concentrate on production from high yield fields primarily in the Timan-Pechora region where it expects to increase production from 8mn tonnes to 23mn tonnes by 2010 and the Caspian where it expects production to reach 16mn t/y by 2010. Currently 71% of Lukoil's production comes from West Siberia and 18% from European Russia. The company is also seeking to concentrate on more lucrative oil refining and asset expansion abroad.

Other Russian oil companies are also following the example of Lukoil and diversifying their sources of income, diverting resources to processing crude and the purchasing of processing facilities abroad to make retail sales independently. Furthermore, to get around future oil export restrictions imposed by the government in response to Opec pressure, they are planning to increase product exports. There are several plans for product export pipelines. Under one proposal European Russia's product pipeline network will be linked to the Baltic port of Primorsk. Lukoil is planning its own pipeline in the same area. A refinery modernisation programme is also currently underway by the Russian oil majors.

Published investment plans

In 2002 Lukoil's income was down to $2bn from $2.11bn in 2001. For 2003 the company has reduced its income expectations to $1.5bn from an earlier $1.7bn based on expected declines in oil prices. Its investment plan for 2003 is also down on 2002, $2.18bn compared to $2.3bn a year earlier.

Production costs at both Lukoil and Surgutneftegaz increased in 2002 to respectively $3.20/b and $2.90/b. Yukos on the other hand reported lower production costs and plans to increase capital expenditure in 2003 to $1.76bn compared to $1.29bn in 2002, of which $1.44bn is to go on exploration and production. At TNK plans call for investment of up to $2bn in its existing upstream projects by 2007. In 2003 its upstream capital expenditure is planned at $380mn. The company hopes to increase output from the current 274mn barrels to 365mn b/y by 2007. Increased production is expected from enhanced oil recovery (EOR) schemes on the Samotlor oil field, which currently produces 136mn b/y and the Uvat project in southwest Siberia where the company holds licence to eight blocks which include seven fields and 29 structures with expected recoverable oil reserves of 300mn barrels. The Uvat project is pending a PSA that is expected to be finalised in 1Q2003.

Yukos, Lukoil, Sibneft and TNK have for the first time joined forces to construct a deep sea oil port at Murmansk, with construction expected to last from 2004–2007. Two pipeline routes are being considered – Surgut (Western Siberia)–Ukhta–Murmansk (3,600 km) and Surgut–Usa–Murmansk via the White Sea (2,500 km).

Encouragement for investors

With better corporate governance and management practices the Russian oil companies have gained the confidence of western investors. For example, many Russian oil companies have adopted US GAAP accounting standards and even have quotes on foreign stock exchanges.

Russia is also trying to open up new export markets in the US and China. It may be able to take advantage of the crisis in the Middle East and the fall out of relations between the US and Saudi Arabia in the aftermath of September 11 to open access to the US market. With the Bush Administration planning to add 120mn barrels to the strategic reserve to bring it up to 700mn barrels by 2005 and reduce dependence on Middle East supplies, Russian producers have been given their best opportunity yet to develop the American market.

Yukos began exporting 2mn b/month to the US in 2002 and plans on maintaining this in 2003. Its longer term plans call for a tripling of total exports to 100mn tonnes by 2010, of which one third will go to the US. Meanwhile, state-owned Rosneft has entered a joint venture with Marathon for the creating of UNAM (Urals North American Marketing) to transport and market Russian oil in the US starting in 3Q2003.

TNK has also started delivering to the US. In an interview last December, TNK President, Simon Kukes, said that aiding the economics of exporting crude oil to the US will be the emerging differential between the Urals prices in Europe and in the US where Russian oil will become more valuable. In Europe Urals faces competition from other crudes whereas in the US, where the refinery system is better designed to process heavier oil, demand for Urals will remain robust and it will will fetch a greater price than in Europe. Such a differential coupled with the security of long-term contracts, Kukes says, could offset the higher transportation costs. He predicts that Russian crude exports to the US could reach 54,000 b/d by the end of 2003.

The Russian oil companies are also being lured to the East by the prospects of tying in Asian demand to Russian oil and gas. Among the Russian oil companies Yukos has the largest reserves in East Siberia in Krasnoyarsk, Irkutsk and Sakha Provinces. The company estimates that East Asian demand for oil will rise faster and further than the US or West European levels within the next decade, reaching 24mn b/d. In 2002 Yukos exported 40,000 b/d to China by rail and expects to raise this figure to 50,000 b/d in 2003. It also plans to extend a Transneft pipeline from the refinery town of Angarsk in Irkutsk in southeast Siberia to the northeastern Chinese terminal centre of Daqing.

The pipeline ties in with the government's strategy to lock in markets for the country's burgeoning oil production. On the Russian side the pipeline will be 1,500 km long and on the Chinese side 800 km long. Oil from VNK's (in which Yukos has a 93% interest) Tomskneft fields and VSNK's (in which Yukos has 70% interest) Yurubchenskoye fields in Krasnoyarsk will feed the pipeline, construction of which is to begin in 2003. The pipeline will provide China with 400,000 b/d starting in 2005, rising to 600,000 b/d by 2010. CNPC has agreed to finance the 800-km of the pipeline on its territory and, as part of its deal with Yukos, Petrochina is expected to take an upstream stake in the Tomskneft and Yurubchenskoye fields. Yukos and CNPC would be the co-owners of the pipeline and Transneft its operator.

Yukos also has a joint venture with Slavneft (now owned by Sibneft-TNK) to develop the Kuyumbinsky field in East Siberia's Yurubcheno-Takhomskaya block in Krasnoyarsk near the Chinese frontier, which is estimated to hold at least 60mn tonnes of recoverable oil reserves.

The Sakhalin-1 (ExxonMobil, Sodeco of Japan, ONGC of India and Rosneft) and Sakhalin-2 (Shell, Mitsui and Mitsubishi) projects which are currently underway are also aimed at the Asian markets of Japan, China and Korea. Both projects are expected to yield a maximum of 400,000 b/d, although the major goal of the two projects is not to produce oil but gas and to ship it by subsea pipeline or as LNG to the Far East. In early 2002 the first phase of Sakhalin-1 was launched. It involves the development of three fields – Arkutun-Daginskoye, Chaivo and Odoptu – with estimated combined reserves of 2.3bn barrels of oil and 17tn cf of gas. First oil production is expected in 2005 from Chaivo and in 2007 from Odoptu, and gas from both fields in 2008. In 2003 investment in the project will amount to £1.2bn, which is some 70% above the 2002 level. ExxonMobil, the operator, is planning to start construction in 1Q2003 of a horizontal well from the Island's shore to the Chaivo field and a 367-km oil pipeline to the port of Dekastri in the Khabarovsk region from where oil will be exported.

Russian government action

The Russian Government is leading the oil industry to the Eastern region of Siberia and the Far East, as well as the offshore Arctic shelf, in an effort to increase investment in the economies of these regions. It is offering 22 blocks in the Barents Sea as part of a long-term strategy for the exploration and development of the Arctic shelf which is believed to contain 16bn boe. According to the Energy Minister Igor Yusufov licensing of the Barents Sea will run through to 2005, with 70,600 km of the Arctic shelf being offered.

The government has also approved a long-term programme for exploration and development of oil and gas reserves offshore Magadan, Petropavlovsk-Kamchatskiy and Anadyr. Eight blocks have been identified offshore Magadan that could yield up to 10bn barrels of oil and 75tn cf of gas. Currently two general lease areas have been earmarked and bids are to be awarded in 2Q2003 under PSA terms.

According to the UFG research data presented in *Petroleum Review*'s review of the Russian sector in February 2002, whereas \$5bn to \$7bn is required to maintain or slightly increase aggregate Russian oil production, much larger amounts of investment are required to make a step change in production. The inference is that \$5–\$7bn is probably the upper limit for domestic sources of finance, which implies that foreign investment would be required.

Company	Production (mn tonnes)
Lukoil	75.49
Yukos	69.88
Surgutneftegaz	49.20
TNK	37.50
Sibneft	26.32
Total, by majors	258.39
Total Russia	379.63

Table 1: Oil production by major companies, 2002

TNK's Managing Director, German Khan, has warned of a decline in oil output in the next few years unless foreign investment is encouraged. The Russian oil companies, he says, cannot raise the requisite funds without outside help.

Contrary to some of the views expressed in the Russian press the disappointing way in which the government handled the auctioning of its 74.95% stake in Slavneft – which accounts for 4% of Russia's oil production – at the end of 2002 for a little over its target price of \$1.7bn is not likely to have a negative impact on western investor confidence in the openness of the Russian privatisation system, according to Jonathan Stern of RIIA, as the joint bid by Sibneft-TNK for \$1.86bn was a 'done deal' that was understood both inside and outside Russia.

Meanwhile, Petrosakh, a subsidiary of Alfa Eko, has been licensed to explore part of Sakhalin's undefined block 6 in the northern end of the Island. According to Alfa Eko's Yuri Shirmankian the cost of initial development of the block is about \$1.3bn and the company plans to invest \$400mn only in developing its section that includes seven structures. The company wants to share its controlling interest with Russian or foreign companies who can share the cost. Block 6 will be the last concession offshore Sakhalin Island and Shirmankian anticipates it will be included in the Russian Parliament's list of PSA contenders. Similarly, TNK, which holds a license to Sakhalin-3 estimated to hold reserves of 1bn barrels of oil and 17.5tn cf of gas, is seeking out a partner to develop its sector.

Factors discouraging new investment

Professor Gawdat Bahgat, a Middle East specialist at the University of Pennsylvania, claims that as opposed to some Middle East producers who have such low marginal extraction costs that they can make money even at \$10/b

New developments in the Russian oil sector

Conoco plans to produce 6,000 b/d from the new Oshkotyn oil field and to develop two other new fields in the Timan Pechora region. Requires investments of $100mn.

- Yukos-Mol, a 50/50 Russian-Hungarian joint venture set up to develop the Zapadno-Malobalykskoye field in West Siberia with reserves of 142mn barrels. Mol is to invest $100mn. The field will provide 55,000 b/d by 2005 for the Hungarian market.
- Yukos-TotalFinaElf joint venture established for exploration in the Eastern Black Sea Basin including the Shatsky Ridge.
- Yukos and Sibneft to jointly explore offshore zones in Chukhotka and East Siberia seas.
- TNK-Sibneft partnership. Sibneft received 8.6% equity stake in TNK International (the main shareholder in TNK and Onako oil holdings) and TNK received 40% stake in Orenburgneft drilling company.
- Lukoilneftegazstroi, the construction arm of Lukoil, has won a contract to build pipelines for Sakhalin-1 that will transport oil and gas between the waterfront and offshore facilities. It is also expected to build a crude export pipeline across Sakhalin to the mainland via Tatar Strait.
- Surgutneftegaz is to launch three new fields in 2003 with combined reserves of 3mn tonnes – Severno-Seliyarovskoye, Severno-Aypimoskoye and Severno-Tonchinskoye in Tyumen Oblast, west of Surgut.
- Lukoil has won 20% interest in the Kharyaga field PSA (TotalFinaElf 40%, Norsk Hydro 30%, Nenetsk Oil Company 10%) in the Yamal-Nenetsk region. The field produces 30,000 b/d and has estimated recoverable reserves of 710mn barrels.
- TNK plans to put 20% of its shares to public tender in the next 18 to 24 months.
- A Gazprom and Surgutneftegaz joint venture is to develop oil and gas condensate deposits of the giant Urengoi gas field.
- Rosneft and Gazprom are to develop the Prirazlomnoye oil and gas field in the Arctic.
- The US is to fund a study to explore four basins in East Siberia and estimate reserves.

prices, for the Russian oil companies' production becomes unprofitable below $12/b. At $15/b Yukos claims it would have to revise down its capital expenditures plan for 2003 which is set at $1.76bn, of which $1.44bn is to go on exploration and development. The figures are based on oil prices of $22/b.

Yukos CEO Mikhail Khodorkovsky blames the decline in oil reserves in the existing oil provinces on the current Law on Mineral Resources that does not stipulate for a licence for both exploration and production. Consequently there is little incentive for the private oil companies to rehabilitate used reserves.

To bring the oil and gas reserves of the Eastern regions and the Arctic shelf on line is going to be a very expensive business. In addition, the Russian oil companies have neither the capital nor the technology to develop these reserves by themselves – yet the government has consistently failed to amend legislation relevant to the PSA framework it passed in the mid-1990s. Simon Kukes of TNK sees PSAs as essential to maintaining sustainable production growth, but he is skeptical that a suitable PSA regime will emerge anytime soon.

Some of the urgency behind the PSA regime has evaporated as the cash flow of the Russian oil companies has improved and they have begun to invest their own money in the sector. But there is a strong anti-PSA lobby both within the government and the oil industry. The Russian majors are still largely concentrating their investments on E&P in the existing accessible oil provinces and do not see the need for foreign participation. Yukos's Khodorkovsky is a strong opponent of PSAs, arguing that it is more profitable for any state to explore its fields on the basis of its own taxation regime than on privileges that are provided to the PSAs. The constraints on oil production are not investment, he says, but sales markets. Support for foreign investment in the sector comes from production companies of the eastern regions where projects are committed to a longer period of time and require large-scale financing.

The Shell-led consortium on Sakhalin-2 has threatened not to proceed with the $8.5bn Phase 2 of the project unless the Russian Government introduces by 1Q2003 the necessary amendments to existing legislation that were promised when the Sakhalin PSA was signed back in 1995. According to Steve McVeigh, CEO of Sakhalin Energy Investment Company, the problem is that all Russian laws in force and those that are still being considered by the Duma openly disagree with the conditions of the PSA on Sakhalin-2. Similarly Archie Dunham, Chairman of ConocoPhillips, complained at the first US–Russia Energy Summit of the non-profitability of the Polar Lights PSA due to almost daily changes in export laws and tax laws.

Another factor limiting the extent of Russian oil production is the lack of sufficient transport infrastructure and sales markets. As the Russian Government currently limits the major Russian oil companies to export 30% of their production and crude oil exports are approaching the limits of the existing pipeline networks there are also concerns that the continued investment will lead to production levels outstripping not only domestic demand but also the country's export capabilities. The state pipeline company Transneft can currently only handle 3.5mn b/d of exported production. However, Transneft is using the recent windfall in oil export tariffs to upgrade its pipeline system and diversify export routes. It plans to add around 15mn t/y (330,000 b/d) of capacity to its pipeline network by the end of 2003.

Without a deepwater port oil exports to the US are not economical for the Russian producers unless oil prices remain very high and allow them to recover their transport costs. Some estimates have put the cost of transporting to the US at $1.50/b leaving producers with a profit of $1–$1.50 at best. Currently, only from Sakhalin Island is it possible to ship crude directly to the US. Transporting the oil to the Far East would be even more uneconomical.

It may well be regarded as symptomatic of the combined economic and domestic political risks that the market capitalisations of leading Russian oil companies are so small relative to international operating companies, even though their production is high and reserves substantial (see **Table 2**).

**According to Poul Thomsen of the IMF Office in Moscow.*

Russian oil company	Capitalisation, Dec 2002 ($bn)
Lukoil	13.0
Yukos	21.0
Surgutneftegas	11.4
Sibir	3.6
Sibneft	10.4
Tatneft	1.7
BP (included for comparison)	150.0

Table 2: Market capitalisations of leading Russian oil companies

Trevitest on-line valve testing

Outsourced maintenance for today's marketplace

Efficient maintenance strategies are increasingly the focus throughout industry as both economic and political/environmental pressures are stepped up. *Tony Nicholls*, Furmanite Business Development Manager, looks at how specialist services could impact the oil and gas industry.

Whilst specialist engineering services and the latest technologies are continually proving their worth in the marketplace there is also a growing appreciation for the need to use both in-house and outsourced skills and resources more effectively. The benefits of outsourcing are increasingly being recognised, indeed outsourcing maintenance of manufacturing production facilities has seen the most considerable quantifiable growth – from some 5% to 30% over the last decade – and the offshore industry has now become very largely dependant on outside contractors.

Although it is clear that the value of experienced in-house staff is high and that this resource must be maintained, it is not always practical to carry out all maintenance requirements in-house, particularly with a wide variety of services to deploy, many of them specialist. The question should be raised: 'Is it really in any manufacturer's interests to seek to become expert in non-core business areas such as pipeline management?'.

Furthermore, maintenance budgets tend to be closely scrutinised and shaved as far as possible, so in-house resources are quite often stretched. Outsourcing may seem to be an additional outgoing. However, where quality technicians and engineers can be sourced, and time and cost efficient services provided, it can often prove a shrewd means of managing plant or platform maintenance and achieving optimum efficiency.

A step further

Taking outsourcing a step further, partnering is increasingly being recognised as beneficial to operators. The need to call in additional labour is reduced, as one technician now meets both general maintenance and specialist service requirements. This, in turn, reduces the number of mobilisations required (particularly valid offshore) and increases flexibility in meeting maintenance needs – all for only a minimal increase in overall cost.

With the growing trend towards reducing the number of sub-contractors in a bid to improve efficiencies, easing management and creating more streamlined businesses, it makes sense to use a company that can provide multi-skilled technicians and avoid multiple sub-contracting wherever possible. Given that proven expertise levels and quality of workmanship are high, the benefits are great, and partnering in this fashion between operator and contractor delivers maximum value.

Furmanite partnership

At Furmanite 'partnership' can range from 'healthcare' packages (such as those offered on valves or steam systems, covering inspection, repair, certification, maintenance, parts, etc), or semi-permanent team members on-site to work alongside in-house personnel, through to a service Furmanite offers whereby a technician is provided to become a permanent member of the maintenance team, fully trained to provide all the Furmanite plant optimisation services.

For BP, just one of the companies using this permanent team member service, having the expertise on-hand for procedures such as dimensional checks and injection requirements enquiries means a rapid and efficient response. Commenting on the agreement and how it has worked for his company, Bill Logan, BP's Offshore Installation Manager and Planning Team Leader, says: 'Historically BP employed internal staff for operations and maintenance and these personnel had accumulated a vast knowledge and awareness of offshore mechanical equipment. Contracting out this type of work imported a high risk factor, but Furmanite's years of experience in the industry has proven invaluable to both the main contractors and BP. Furmanite's presence within the maintenance teams ensures that all planned and corrective tasks that arise within a mature asset such as these platforms can be addressed quickly, efficiently and successfully, and maintenance requirements executed safely and competently.'

In other instances, having a semi-permanent team of technicians on site can be the optimum way forward. For example, the Shell Stanlow complex at Ellesmere Port employs Furmanite as its contracted specialist for all the site's leak-sealing and on-site machining needs, ensuring that situations are dealt with quickly and efficiently while avoiding unnecessary downtime.

With such a broad range of services Furmanite's core aim is to keep assets earning and maintain maximum efficiency levels. It does this by bringing together the right combination for each specific plant/platform. Multi-faceted offerings such as this could provide the key to operators struggling to meet legislative demands while maintaining production and profitability.

Furmanite services covered by these agreements include on-line leak sealing, in-situ machining, controlled bolting, Trevitest on-line valve testing and advanced composites repairs. Furmanite is now also producing more complex bespoke designs for the installation and certification of clamps for hydrocarbon pipework, and ensuring that the stocks and shelf lives of the injection products are being managed, as well as performing tasks on all the platforms that fall outside the maintenance contractor's domain. Furthermore, operators have access to advice on the latest chocking development for the offshore market, Smart-Shim (developed in association with AMEC) and advanced carbon fibre composites repairs (offered through the FDA – an alliance formed last year between Furmanite and DML Composites, see *Petroleum Review*, October 2002).

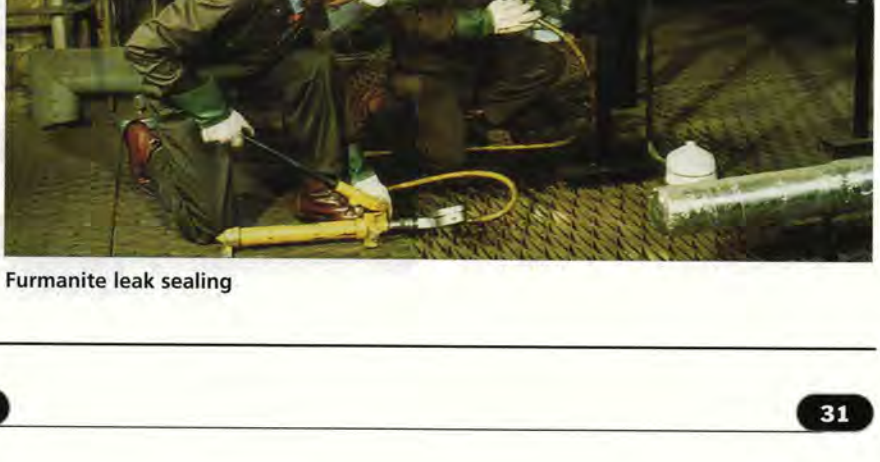
Smart-Shim chocks in position on BP Bruce

Proactive approach

Achieving effective maintenance and efficient operation in line with the triple bottom line requirements of today's marketplace – financial, yes, but also upholding environmental and social responsibilities – requires a proactive approach that is not limited to looking solely at direct costs but instead considers what achieves the best value for each company's assets.

Maintenance is not an insurance policy – handled correctly it will pay dividends, handled badly it will incur costs. An effective maintenance plan, making the most of plant and skills, can bring substantial gains by maximising efficiency and productivity. At this time of growing focus on maintenance the variety of levels of outsourcing and partnership can be used to suit the needs of each individual plant and provide an optimum solution for maximising plant efficiency in every sense.

For further enquiries, contact: T: +44 (0)1539 729009 www.furmanite.co.uk



Furmanite leak sealing

Securing the future of UK gas

In November 2002 the Institute of Petroleum (IP) and the Petroleum Services team at Deloitte and Touche held a joint workshop at the Institute for leading UK gas industry executives. The aim was to allow the participants to exchange ideas and views on the future of the UK gas industry at what appears to be a key turning point in its development and ahead of the publication of the UK Government's White Paper on Energy Policy in 1H2003. To facilitate a frank exchange of views the workshop was held under Chatham House rules. This means that the names of individuals and their company affiliations cannot be reported, although their views and conclusions can, writes *Chris Skrebowski*.

A number of key messages came out in the presentations and discussions. However, the single most important message was the requirement for a clear energy policy from the UK Government – preferably one that was based on market mechanisms. Participants largely agreed that the energy market in the UK had changed radically in the last 10 years and generally to the benefit of customers. Looking forward the picture becomes less clear. While it was generally agreed that gas demand would continue to grow, and at a faster rate than for other fuels, the major challenge was to provide a competitive and secure supply of gas, particularly after 2006, the date when UK is expected to become a net gas importer.

Future supply policy

The prospect of expanding gas imports raised concern as to whether future supply policy will predominately be set by the market or by government. The UK Government was seen as having to reconcile three principal objectives:

- The promotion of an energy market that delivers diverse, secure and affordable energy supplies.
- The reduction of the carbon intensity of the national energy mix by the promotion of the use of renewables, nuclear or lower carbon energy sources such as gas.
- The requirement to increase tax revenue as production of indigenous supplies declines. This would particularly impact the upstream sector, but the government would also need to ensure that there was adequate investment in the infrastructure needed to support efficient energy supply.

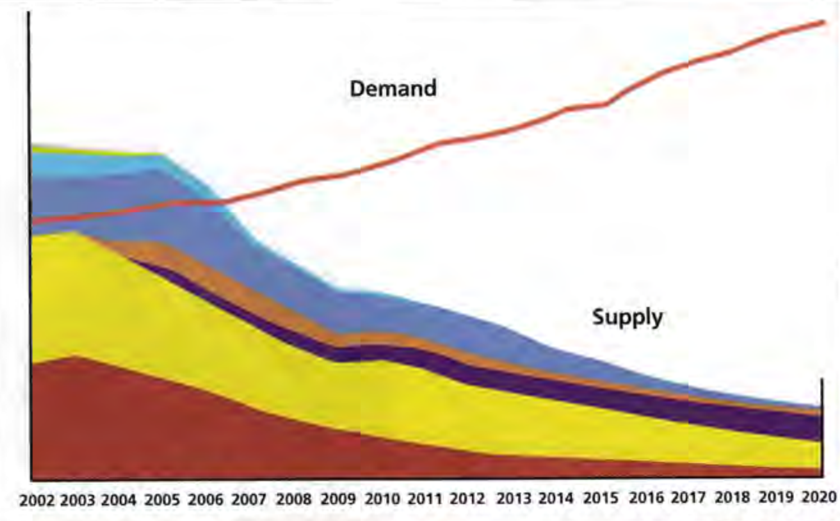
A number of concerns

Individuals representing different segments of the industry present at the workshop tended to focus on somewhat different concerns. For those operating in the upstream sector the main concerns were the government's recent introduction of higher North Sea taxation, both in terms of its direct impact on investment and returns and as a precedent for future tax change. Other concerns were the size of the investments required by the market and the need for a stable and predictable policy environment to justify and fund such investments. They were also concerned that any government policy should be equitable and to be seen to be so. There was a strongly held view that the UK Treasury's priority was revenue maximisation above everything else.

The creditworthiness of customers, post Enron, was another area of increasing concern. There was a consensus that gas supply would tend to lag demand with little new investment being made until prices were higher and perceived investment risks lower. With taxation the largest single cost to many companies, participants were particularly critical of the government's additional taxation in 2002 and very concerned that government policy becomes clear and stable. Another area of concern expressed by participants was where the margin was going to be taken – in the upstream, the midstream, the downstream, or by the government in the form of taxes?

Supply and demand

Participants recognised that in the UK sector gas finds were becoming smaller and the market increasingly mature with smaller niche players becoming more important in the development of small accumulations. It was felt, however, that the big oil companies would



The emerging supply/demand gap for UK gas is most strongly illustrated by analysis of the projected declines in landings at Bacton, from the southern sector gas fields, and the steady growth in demand from the terminal maintain their control of the supply infrastructure thereby maintaining their importance in the supply chain even as the volumes of their own production declines.

Noting that gas is the 'fuel of choice' most participants agreed that the main requirements of the UK Government were that it should smooth the path of foreign gas imports into the UK, keep the market fully competitive and defend it from the dominant European companies who have the advantage of deferred market liberalisation in their home markets. The principal threats were seen as weak or contradictory governance and excessive taxation.

Participants involved in the logistics arena were very much focused on the increasing volume of pipeline gas imports into the UK and the likely viability of LNG imports. With a number of new import pipeline proposals being discussed they felt it was important that market driven solutions be adopted. The funding and economic justification of large-scale projects was seen as favouring longer-term contracts and this, in turn, was seen as favouring the larger players possibly at the expense of the smaller and more innovative players.

In the short-term they saw the supply/demand balance being maintained largely by demand erosion in the industrial sector in reaction to firming prices and the tightening markets. However, no sustained increase in the gas price was foreseen. The view seemed to be that provided the government didn't interfere and distort the market, security of supply could grow organically as import infrastructure was built and imports of gas increased.

The continuing growth in gas demand was seen as inevitable given environmental restrictions on coal use, problems in the nuclear industry and the intermittent nature of renewables. An increasing role was seen for LNG as it was viewed as a plentiful, widely dispersed and relatively low cost source of supply. It was also noted that LNG is likely to become increasingly competitive as technology lowers production costs and multiple facilities provide supply competition.

Participants from the downstream sector of the market were confident of the market's future but very cynical about the upcoming government White Paper on Energy Policy. Their view was that the problems of the nuclear generator – British Energy – would drive the policy. The government needed to 'save' British Energy and this would be achieved by stressing the cost of carbon emissions, thereby enhancing the importance of carbon-free nuclear power. This cynical theme continued with the view that dreams of a separate UK gas market will disappear as imports rise as the UK market becomes an extension of pan-European markets. They believed that as North Sea revenues dwindled the government would increasingly tend to focus on tax management but that it would maintain the two tax regimes for offshore and onshore operations as at present. Increasing volumes of LNG imports into both the UK and the Continent meant that some form of LNG trading hub was likely to emerge, based around Milford Haven, the Isle of Grain and Zeebrugge.

Wait and see

All the participants agreed that the meeting and its format had been a success. It only remains to see the exact details of the UK government's White Paper on energy policy* and whether the worst fears or the best hopes for the UK gas market have been realised.

Publication of the White Paper has been delayed and it is now uncertain when it will be published. However most commentators still favour sometime during the next few months.

Further details and documentation on the gas workshop are available from Kelvin Beer, Senior Manager, Gas at Deloitte and Touche on T: +44 (0)20 7438 3569 or e: kgbeer@deloitte.co.uk

Following the tremendous success of the gas workshop the IP plans to hold further workshops and would much appreciate suggestions for topics from readers. Please contact Lawrence Slade, IP Marketing Director, on T: +44 (0)7467 7103 or e: lslade@petroleum.co.uk

IP Awards of Appreciation

Rae Crawford (left) with Brian Abbott, IP Technical Director

Rae Crawford was awarded a Certificate of Appreciation in December in recognition of his services as founding Chairman of the IP's Soil Waste and Groundwater Group. He has Chaired the group over the last four years, during which time excellent work has been carried out on behalf of industry on a number of issues including MTBE occurrence in UK groundwater, guidance on risk assessment and work on soil vapour movement. Rae has also been very influential in creating closer links with the regulators and much of the group's work has been carried out jointly with the Environment Agency. He is moving internally within ExxonMobil to take up a new role and has decided to stand down as WG Chairman.

Alan Chamberlain (left) with Louise Kingham, IP Director General (right)

Louise Kingham recently presented Alan Chamberlain with an IP Award of Council for his meritorious work in the field of petroleum measurement, marine transportation loss control and cargo inspection.

A founder member of the IP's PML 3 Cargo Inspection Panel, Alan was a leading light in the development of the three IP Cargo Inspection Guidance documents used by the industry worldwide. He became Chairman of the Panel in 1990 and was appointed Chairman of the Petroleum Measurement Committee in 2000.

Alan was also very active in BSI and was a regular member of the UK Delegation to ISO Petroleum Measurement Meetings. He was the IP's principle liaison with the API on petroleum measurement matters. The API awarded him a Certificate of Appreciation in 2002.

Delight and embarrassment

Two oil discoveries – one 'real' offshore Mauritania and one 'imagined' onshore Morocco – coupled with contested exploration licences over the disputed offshore territory of the Western Sahara have generated delight and embarrassment in equal measure for operators in what used to be regarded as Africa's least promising hydrocarbon region, writes *Maria Kielmas*.

The first of the discoveries, offshore Mauritania, was announced in 2001 by a Woodside Petroleum-operated consortium that included Hardman and Fusion. The Chinguetti-1 well, drilled to a total depth of 4,000 metres in 700 metres of water, encountered a 90-metre gross oil column with crude oil density just below 30° API. The discovery sent the share price of the smaller consortium partner companies soaring and stock market analysts wondering what was the catch. The reality check came in late July that year when the second well, Courbine-1A, came in dry and the companies' share prices plunged between 15% and 35%.

Drilling of the third well, Banda, in 300 metres of water in 2002 indicated the presence of a 23-metre gross oil column overlain by a 110-metre gas column. The find was in turbidite sands, which generated even more excitement among geologists who were ready to compare the region with similar prospects offshore such as Brazil and in the Gulf of Mexico. However, the share prices of consortium partners Woodside, Hardman, Fusion and Roc Oil fell in response to world stock market nervousness over recession and a war in Iraq.

Fusion and Hardman were the first of the consortium partners to work up Mauritanian prospects, signing production sharing contracts PSC A in 1996 and PSC B in 1998. The companies later farmed out to Woodside and British Borneo (now Agip). The companies only acquired the acreage because it was rejected by Shell at the last minute. According to insiders, the Shell team working on Mauritania left en masse to work in the Gulf of Mexico with Unocal and their replacements at Shell decided that Mauritania was not a viable prospect for a large major.

The Mauritanian Government has since redesignated all of the offshore exploration blocks as Chinguetti followed by a number, with the wells within each block following in numerical order. Thus the Banda well is Chinguetti 4-3. Previous drilling offshore Mauritania between 1969 and 1991 encountered oil shows and source rock, but the wells were located in less than 200 metres of water. The Chinguetti discoveries are in Miocene channel sands above a salt basin. It had been hoped that the Chinguetti 6-1 well would test how the thickness of sands over a salt diapir may increase down the flank of the structure towards the southeast, however it was plugged and abandoned in early November 2002.

The channel system does not extend into the northern blocks presently held by a Dana Petroleum-operated consortium, but is thought to be present offshore the Western Sahara. The initial thinking by companies was that the Miocene sands were above a Cretaceous delta system. The delta was identified on satellite photographs but the paleo river system with which it was supposed to be connected was not. The current thinking is that the northern Dana-operated blocks are located above a large carbonate platform with clastic provinces to the north, offshore the Western Sahara, and to the south in the Chinguetti region. But whether these clastics are turbidites offshore the Western Sahara is unknown.

Moroccan fiasco

The Mauritanian terms of zero royalty, 60% cost recovery, a production split between 50% and 70%, and income tax of 25% are superior to those now being offered by Morocco. Previously Morocco had offered very generous development terms, reflecting its complex onshore geology and lack of discoveries. However, in October 2002 the Moroccan Government, through state oil company Onarep, launched an offshore exploration round for eight blocks ranging from the shoreline to water depths of 3,000 metres. New legal and fiscal terms on offer this time were supposed to reflect a growing industry interest in deepwater exploration. Royalties were increased from zero to 10% for oil and 5% for gas, and Onarep was given the option of being carried for up to 25% of each licence. Acreage rentals were almost US$100/sq km/y – very expensive for wildcatting acreage.

As a result industry response to the offer has been poor. The situation was little helped by a fiasco prior to the bidding round launch. King Mohamed VI announced that 20bn barrels of oil had been discovered in the east of the country by Lone Star Energy (an affiliate of Texas-based Skidmore Energy) with just one well, Sidi Belkacem-1 in the Talsinnt permit.

Lone Star Energy was a joint venture between Skidmore and Mediholding. The latter, which initially held 25% of Lone Star, is headed by Moulay Abdellah Alaoui, a cousin of King Mohamed VI and who was briefly Energy Minister during the 1990s. Mediholding's

Exploration Director is Rabah Bouchta, former General Secretary of Onarep. Other Directors are Othmane Skiredj who is from a military family and Rabat banker Mohamed Benslimane.

The company later announced that the discovery indicated, but did not prove, that potential reserves in the prospects in question were between 50mn and 100mn boe. Subsequent embarrassment over the exaggeration of the discovery led to the dismissal of the then Energy Minister Youssef Tahiri and the then long-serving Onarep chief Mohamed Douieb.

Claims of vast oil discoveries in the regions around the Moroccan–Algerian borders have been made with predictable regularity ever since 1954 when what was then French-controlled Algeria first offered acreage around Tindouf (western Algeria) for exploration. Indeed, such claims have become a standing joke among seasoned Moroccan and Algerian specialists.

Dispute over Western Sahara

Rabat's award of reconnaissance licences over the disputed offshore Western Sahara to France's TotalFinaElf and US-based Kerr-McGee has generated a lot of controversy. The Moroccan Government, through Onarep, has always declared that the Western Sahara would be licensed out as any other Moroccan territory. The present award to companies from the US and France has generated some irreverent remarks from upstream professionals – a number of whom were hoping to broker exploration deals in the area through Onarep – that the area is now partitioned 'between the CIA and the Deuxième Bureau'.

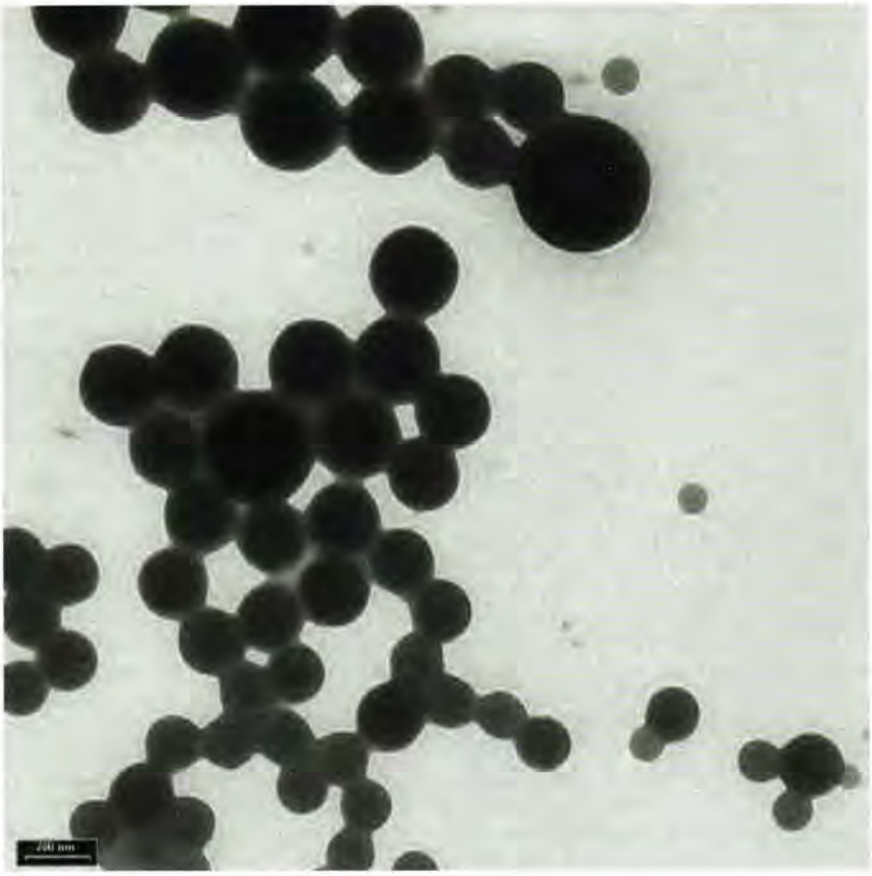
France has always championed Moroccan sovereignty over the Western Sahara, so the award of acreage to a French company came as little surprise. The US situation however, appears compromised as Washington takes a more pro-Moroccan stance to its previous policy. The UN's special envoy to the Sahara, former Secretary of State James Baker III, threatened to resign if the Security Council does not declare itself in favour of an 'autonomist' option for the Western Sahara – ie that the region becomes an autonomous southern province under the sovereignty of Morocco – a stance not unlike France's. But his son, James Baker IV, is head of Washington-based law firm Baker Botts LLP that acknowledges Kerr-McGee as a client on its website. The site also advertises the available expertise of the former Secretary of State James Baker III.

A letter dated 29 January 2002 from the Under-Secretary General of Legal Affairs, Legal Counsel, Hans Correll, to the President of the Security Council, concluded that whilst the TotalFinaElf and Kerr-McGee contracts were not in themselves illegal, 'if further exploration and exploitation activities were to proceed in disregard of the wishes of the peoples of Western Sahara, they would be in violation of the principles of international law applicable to mineral resources and activities in Non-Self-Governing-Territories.' Non-Self-Governing Territories are disputed territories such as East Timor prior to its independence.

The future of the Western Sahara has been dealt with by the UN Security Council since 1988 when the Moroccan Government and the Polisario insurgency group agreed in principle to aim for a peaceful settlement of the dispute through a referendum. The referendum has been postponed continuously ever since. The Polisario-controlled, self-proclaimed Saharawi Arab Democratic Republic was recognised by Algeria in 1976, by Mali in 1980 and by Mauritania in 1988. Polisario spokesmen have always welcomed any approach from international oil and mining companies interested in exploring natural resources. However, few companies made the effort to approach the group until June 2002 when Fusion Oil & Gas signed a reconnaissance permit over the entire offshore area with the Polisario Government.

Fusion's idea was to follow interesting prospects along the West African coast from southern Senegal through Mauritania and into Western Sahara. The company's first move was to contact the Foreign and Commonwealth Office in London in 1999, which in turn referred the company to Polisario's London representative Ibrahim Mokhtar. Negotiations for the permit took place in London, Sydney and Seville. The final technical cooperation agreement was signed in London by Fusion directors and Daf Mohamed Khaddad, the Secretary General to the Presidency of Polisario Mohamed Abdelaziz.

The company will be able to compile a technical report on the area from accumulated and available technical data. If there is a settlement of the dispute in favour of Polisario then Fusion has an exploration contract. If there is no settlement there is little to stop TotalFinaElf and Kerr-McGee from proceeding with exploration.



Emulsions aiding deepwater development

Emulsion technology is not a new science. However, it is of very significant importance in crude oil production and is now finding new applications in oilfield chemistry which are providing invaluable assistance in the development of deepwater fields and those with other difficult technical challenges, reports consultant *Phil Wheeler*.*

Above: Water droplets flocculate as emulsions age

Most crude oil is produced in the form of an emulsion. In the overwhelming majority of cases this comprises a dispersion of small (1–20 micron) water droplets in the crude oil. The water originates from both the natural aquifer underlying the reservoir and water (often sea water) injected to maintain production rates. These emulsions are formed when a mixture of crude and water passes through the wellhead choke that is designed to reduce the pressure before the produced fluids reach processing facilities.

In the absence of any stabilising chemicals the water droplets would coalesce into larger particles and eventually separate under the influence of gravity. However, in most cases this does not happen spontaneously because crude oils contain chemical components, such as asphaltenes, waxes and 'resins' (non-hydrocarbon chemicals) that accumulate at the oil/water interface and prevent droplet coalescence. These chemicals need to be displaced before droplet coalescence can occur and the water can be separated from the crude oil. It is undesirable to pump large quantities of water from production facilities to refineries for several reasons:

- it utilises capacity in transporting a valueless commodity,
- it increases the risks of corrosion of pipelines and downstream facilities, and
- it adds to downstream disposal costs because as emulsions 'age' they become harder to separate.

The displacement of the crude oil surfactants from the oil/water interface is normally achieved by a mixture of heating and chemical treatment. Crudes with high wax contents must normally be heated above 50°C to achieve separation in a realistic time. Other surface active materials which would normally be in the liquid state are displaced by a mixture of low molecular weight polymers and other chemicals that have a higher affinity for the water droplet surface but which do not inhibit coalescence (provided they are not overdosed – see below). Typical residence times in oil/water separators are between 5–10 minutes and thus these chemicals must be very efficient. Their efficiency increases with increasing temperature and for some of the more intractable emulsions or crude streams, which arrive at gathering stations at low temperatures, it may be necessary to provide artificial heating.

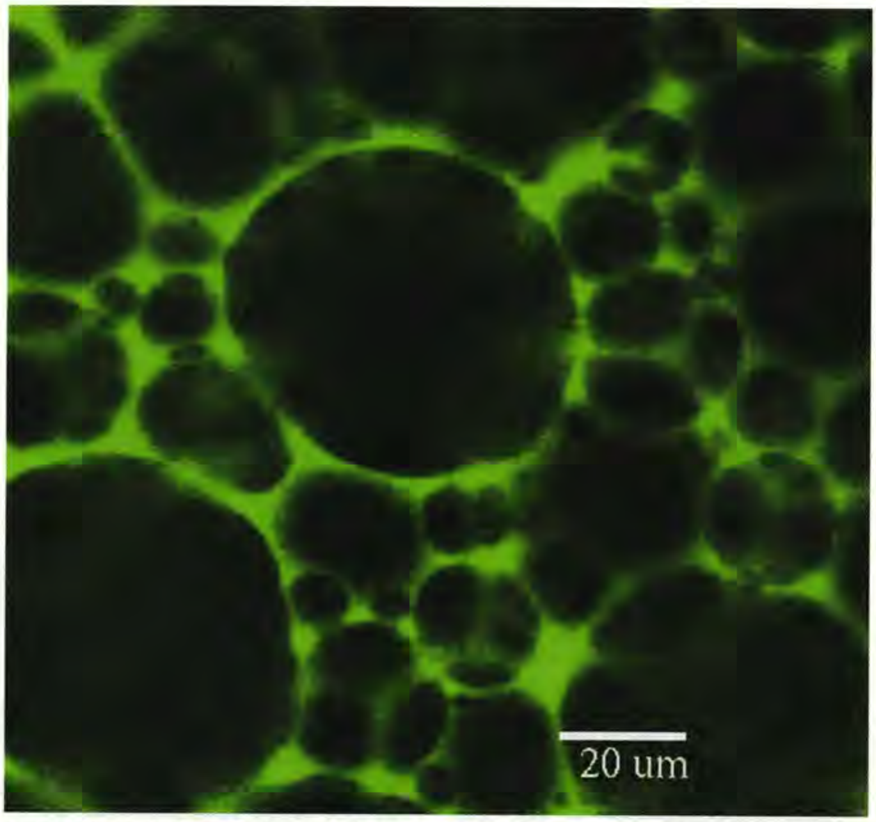
A number of fundamental studies have been carried out over the years to understand the mechanisms of the processes on a molecular level. These have enabled the complexities of demulsification to be better understood and have allowed chemical companies to develop more effective emulsion breaking products. However, due to the almost limitless variations in crude compositions it is usually found that the most efficient demulsifier blend will be specific to the particular crude for which it is formulated.

Oilfield scale inhibitors

Whereas stable emulsions are unwelcome in crude oil production they have considerable advantages for the deployment of oilfield chemicals. The control of barium sulphate or calcium carbonate scale deposit formation in production tubing is a major problem for many fields. These scales form when incompatible saline waters mix, for example when sea water, injected to maintain reservoir pressure, encounters formation water. The result is that the effective diameters of production tubing are decreased and the efficiency of topsides equipment is reduced due to interference with oil/water separator internals etc.

Conventionally these scales are treated by injecting a high concentration solution of water-soluble scale inhibitor, typically phosphonate or polymeric molecules. This 'squeeze' treatment requires ceasing production from the target well for as much as a week. The scale inhibitor is retained within the reservoir matrix and when production is restarted it is slowly returned with the production fluids. Initially the level in the produced fluids is high as the high inhibitor concentration near the wellbore is depleted, but it gradually settles down to a slow decline. Once the concentration falls below the critical level required for protection against scale the squeeze process is repeated. The frequency of treatments will depend on the severity of the scaling problem.

A considerable amount of effort has been directed towards improving the longevity of the squeeze process by increasing the retention of scale inhibitor in the reservoir – ie by slowing the decline of the returning chemical concentration over time. One efficient method is to emulsify the aqueous solution of inhibitor chemical within an emulsion (known as a water-in-oil emulsion). The supporting medium for the water droplets containing the inhibitor is normally a high flash point mineral oil. High energy mixing process equipment is used to produce very small droplets (typically less than a micron). This efficient chemical dispersion ensures that the injected inhibitor



Demulsifiers displace crude oil surfactants leading to progressive droplet growth

chemical blend is very well distributed within the reservoir matrix. When production restarts the droplets release the emulsified scale inhibitor chemical very slowly and the returning concentration remains above the critical protection level value for longer than in the case of conventional solution treatments.

A second type of formulation is a water-in-oil-in-water emulsion. Here the scale inhibitor is first emulsified into a high viscosity oil or low melting wax, which is then further emulsified into water. This can have the advantage over the water-in-oil type of 'protecting' the scale inhibitor more efficiently against the harsh downhole environment and slowing the release, further increasing the interval between squeeze treatments. It can also allow the formulation to be tailored to a specific reservoir by ensuring that destabilisation occurs rapidly over a narrow temperature range.

The formulation of these emulsions can present considerable technical challenges. Firstly, scale inhibitors are often acidic materials and specialist emulsifiers are required to ensure that they can be stabilised. The equipment necessary to manufacture the products also has to be capable of withstanding the harsh materials. Secondly, the choice of emulsifier is also dictated by the need to ensure that the emulsion remains stable under ambient temperature conditions for several months (for logistic reasons) but will destabilise readily under the higher temperature conditions of the reservoir. The water-in-oil-in-water type can be particularly difficult to maintain in a stable condition. Thirdly, it is necessary to ensure that the emulsifier system chosen will not upset the oil/water separation processes within the produced fluids.

The commercial advantages of prolonging intervals between squeeze treatments can be very significant. For example, if a well producing 5,000 b/d only needs to squeezed every six months rather than every three months, two well downtime periods of approximately one week can be saved every year. This equates to an extra 70,000 barrels of oil produced with a current market value of approximately $1.8mn.

Pipeline drag reducers

Turbulent flow in pipelines can reduce throughput significantly. For a given diameter there is a critical flow rate above which turbulence occurs in the liquids being transported. This can be substantially reduced by forming a 'lubricating' film along the pipeline walls that ensures there is a progressive increase in flow rate from the walls to the centre.

Common chemical types used for this purpose are high molecular weight polymers. These materials are often difficult to handle due to their adhesive qualities. However, they can be

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Shaping a new future

Petroleum Review recently interviewed _Louise Kingham_ (right) to find out her impressions after three months as Director General of the Institute of Petroleum.

Louise began by explaining that she had been motivated to take up the post of DG because the IP was in the midst of exploring major options for change. Her first task had been to progress the merger proposal with the Institute of Energy (InstE) to a position that gave all members an opportunity to vote on the proposal. Issuing the Merger Prospectus early in the New Year saw this task completed. However, the outcome of the members' vote would determine one of two paths for Louise to take on members' behalf – the creation of a new Institute or change significant enough within the IP to signal a new phase for the Institute on an independent basis. Whatever the collective decision of the members, her work would just be beginning.

Past experience

Asked about her time at the InstE Louise explained that when she joined it was a small professional body with many of the attributes of a closed private club. At the outset she had planned to stay no more than six months. What had changed her mind and caused her to stay for nearly a decade was the fact she was given the challenge of shaping, and later running, the InstE. She believed that the success she and her colleagues had in transforming the organisation as its members know it today was the result of listening to all the interest groups, and in doing so, balancing change for the better with a respect for the organisation's past – its heritage. The evolution that resulted was driven by her capacity to be outward looking, developing the InstE's relevance towards the communities it was established to serve.

She went on to explain that 20 years ago recruiting members was not a challenge – managers practically instructed their employees to join. Discussions about the benefit of joining an institute were unnecessary. But the world had changed and all institutes had to become relevant to members' contemporary needs. The InstE had been dominated by the supply industry – until it changed its name to the Institute of Energy in 1979 it had been called the Institute of Fuel, with interest focused on fuel policy debates driven in the majority by members from the nationalised supply industries.

The privatisation of the 1980s and 1990s brought a whole range of new organisations into the gas and power markets. The switching from coal to gas for power generation brought further changes, mixing up and changing who was and who should be members of the InstE. The Institute adapted quickly, widening access to its services and, where appropriate, over a longer timescale, introducing new services to appeal to individuals and organisations in the developing energy industries. As an example, the evolving marketplace for alternative energies and new energy forms brought new members and, with them, new areas of interest for current members, roughly in proportion to the investments in the new technologies.

Most recently the largest single change impacting on the InstE and its members has been the volume of consultation and debate to develop a UK Energy Policy. This debate has stimulated interaction between members working in the supply and demand side industries, reinforcing the relevance of the professional body as an independent and credible facilitator of the debate.

IP – first 90 days

Louise was not keen to make quick judgements based upon the words or experiences of others so her priority was to meet as many members as possible and work with the staff team to build her own understanding of the IP. She recalled a number of early impressions.

Essentially a small business in the not-for-profit sector, the IP's successes over 90 years were a credit to all who had contributed to its evolution in the past. Change was not new for this organisation. Survival and success over such a long period would not have been possible without it. This was reassuring even if it was a point not widely recognised.

Even though Louise had worked within the energy world for nearly a decade, until she joined the IP team she had been unaware of the sheer volume and variety of products and services the IP provided to individuals and organisations in the international oil and gas industries. She noted this simply as: 'We must ensure we are not a well kept secret'.

Members she talked to shared Louise's early view that internationally the IP was known specifically by key products and services rather than its broader organisation. The technical codes and standards and IP Week were well understood, but other valuable services were not so.

The willing support of members to volunteer their time and resources was impressive. But more than that, from the IP's most wise statesmen to the youngest and newest members that she met there was a strong desire to break new ground and widen the IP's horizons. In addition, the spirit of the donor putting something back into their professional organisation was still very strong.

Change in the industries it serves, such as convergence and consolidation, has a direct influence on the success or otherwise of the IP. Whether this is manifested as reducing members or less call for a code of practice for example, the impact for a small organisation can be severe over a fairly short timeframe. The spirit of the donor can come into its own in this situation but looking outward and understanding our environment is how we manage the risk this direct link brings.

In short, the IP was a very sound organisation with many positive attributes. The underlying message was simply that it was getting ready to evolve once again. It would be for the members to determine the Institute that would emerge. But some key elements were clear:

- The organisation would be relevant and to be so it would need to be nimble and quick to adapt to industries' demands.
- Donors would continue to be well respected and appreciated, but members and others with an interest in the organisation would also be treated as customers.
- Key values would be held dear and reflected in our actions – independence, quality, sound science and value for money among them.
- Communications would be improved.

A new approach

Louise is not what you might expect to find if you were to conjure up the image of the Director General of a professional institute. 'The job title to me is really rather grand and I would expect all Managing Directors of small enterprises to agree,' she said with a smile. All of my predecessors will have brought certain individual qualities to the IP. I hope that I will create an environment where others can excel, be they members, staff or volunteers. To me that's what a professional body is meant to achieve, regardless of its industry or discipline. If I can bring a sense of spirit to the organisation that means all find a benefit from their involvement with it I will have done what I set out to do.

Merger Proposal

As members receive this issue of *Petroleum Review*, voting on the merger proposal would be closing and the counting underway. A major announcement about the proposed merger would be made during IP Week, as the first opportunity to inform members of the international oil and gas industries how we will be shaping our future. For those unable to attend IP Week please visit the IP website **www.petroleum.co.uk** for the latest news.

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deployed in the form of emulsions in which a low viscosity aqueous layer surrounds the polymer droplet.

In contact with produced fluids these emulsions break and the polymer adheres to the pipeline wall. Using low shear emulsification technology it is possible to incorporate very high concentrations, thus allowing the additives to be deployed in an extremely economical manner. Similar technology has been used for heavy fuel emulsions (such as Orimulsion).

Combined oilfield chemical delivery

Apart from scale inhibitors, other oilfield chemicals such as corrosion inhibitors are also delivered by squeeze treatments with similar loss of production time. Unfortunately, it is often the case that the most effective corrosion inhibitors are oil soluble whereas scale inhibitors are water soluble. Thus corrosion inhibitors are delivered in a solution in diesel oil or other appropriate hydrocarbon carrier whereas the scale inhibitors are deployed in water. As these two are incompatible the treatments have to be carried out separately. This leads to further well downtime with financial penalties as outlined above.

Emulsions offer the opportunity to deliver both types of oilfield chemical simultaneously. One option is to emulsify a solution of the corrosion inhibitor in a suitable hydrocarbon solvent into the aqueous solution of a scale inhibitor. A second possibility would be the emulsifying of the scale inhibitor into the solution of oil soluble corrosion inhibitor.

In addition to reduced well downtime, the benefits of such combined delivery include:

- reduced storage space/increased flexibility in use of existing facilities for chemicals,
- reductions in engineering costs if potentially aggressive chemicals could be 'protected' within an emulsion,
- lowering of the risk from direct contact of personnel with undesirable solvents, and
- performance as a result of improvements resulting from extended squeeze lifetimes.

Protection of pipelines from water

There are circumstances when it is desirable to protect pipeline surfaces from exposure to water. This could be where there is very high salinity water co-produced with oil at satellite locations and where there are thus long pipeline residence times, or possibly in pipelines carrying processed oil from gathering stations to refineries. It may be advantageous to add small quantities of carefully selected emulsifiers to keep water in emulsified form just long enough to reach the next processing point. Concentration optimisation is critical in such applications to prevent plant upsets because the types of emulsifiers added for this purpose would be similar to the indigenous surfactants responsible for the natural stabilisation of produced oil emulsions.

One approach is to add an excess of demulsifying chemical. These products can sometimes stabilise emulsions when overdosed. Indeed this is one of the pitfalls to be avoided in treating produced oil emulsions. As water cuts rise and separator temperatures become lower it is tempting to increase demulsifier concentrations in the separator to deal with the harsher conditions. Unfortunately the tendency is to overdose and saturate the oil/water interface with chemical, thus stabilising the system.

However, this phenomenon could be used to good effect for pipeline protection. We could envisage a situation when a particular well stream is overdosed with demulsifier chemical injected at the wellhead. This would then mix with untreated streams in the separator where smaller amounts of demulsifier are injected such that the overall concentration of emulsion breaker is optimum for the crude mixture.

Overcoming production problems

The aim of this article has been to give a few examples of the ways in which emulsion technology can be employed to overcome problems that will be encountered in the more difficult production conditions associated with the development of marginal fields necessary to counter dwindling global reserves.

The technology has much to offer and new ways of using emulsions are constantly being devised.

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Find out more about the author by visiting the IP Consultants Database, accessed via the 'IP Consultants' link on the Institute of Petroleum's home page at www.petroleum.co.uk

Restructuring the Israeli oil market

Yoav Armoni* reviews the reform of Israel's oil market and suggests what is needed in order for the process to achieve its ultimate goal of creating a truly competitive domestic market across all sectors. The ideas advanced to complete the move from a fully controlled to a competitive arena could have application in many markets around the world.

Disadvantages of current structure	Advantages of future structure
ORL is a refining monopoly that prevented direct marketing of products to the end-user	Two privatised and combined refining-petrochemicals-marketing corporations
Full ex-refinery price regulation	There would be two to three niche marketing companies
Government owned (74%)	Free supply and pricing system

Table 1 : Why restructure the Israeli refining sector?

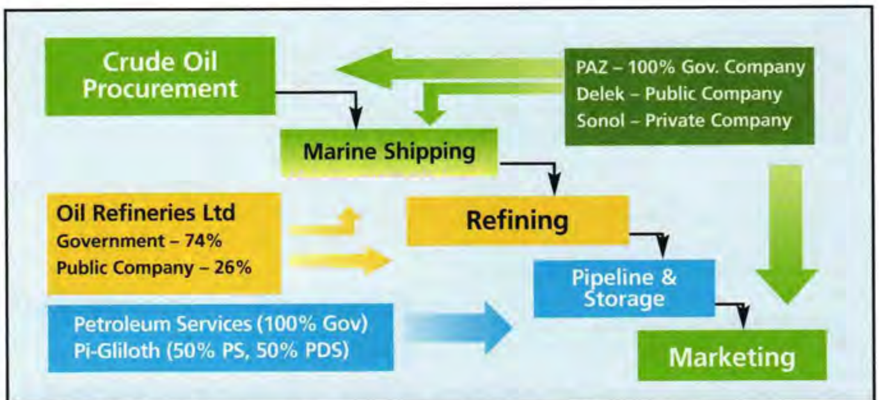

Figure 1: Activities structure in the Israeli oil market prior to 1988

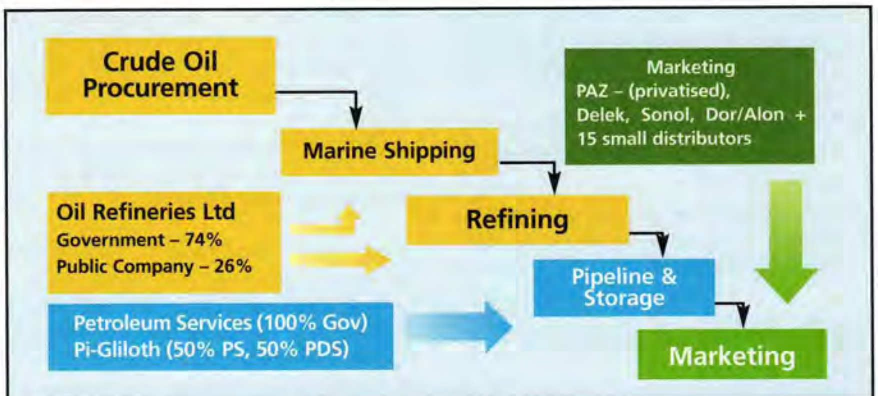

Figure 2: Activities structure in the Israeli oil market after reform

Carmel olefins polyethylene plant near Haifa refinery

Until 1988 the entire petroleum sector in Israel was highly centralised, with the government authorities dividing the market among just three oil companies – Paz, Delek and Sonol. These companies controlled all activities, including import of crude oil, transport, refining, distribution and marketing of petroleum products. The sole refining operation – Oil Refineries Ltd (ORL) – served merely to process crude for the oil companies in return for refining fees. The sector was tightly planned and controlled by the government and functioned on a cost-plus basis.

In addition, the most important companies in the oil sector were controlled by the government. It held a 76% stake in ORL, 100% of the storage and national products pipeline grid monopoly Oil and Energy Infrastructures (OEI), 50% of the distribution terminals monopoly Pi-Gliloth, and 50% of the crude national pipelines monopoly, the Eilat-Ashkelon Pipeline Company. (See **Figure 1**).

The reform process

In 1988 the government began to reform the Israeli oil sector in a bid to reduce its involvement while assuring efficient supply of petroleum products, with economic-based prices and prevention of market failure. Implemented gradually, the process included the end of the cost-plus basis system, ending the price control of petroleum products (prices for the end-user) and enabling new companies to operate under competitive conditions.

In addition, ORL began to operate independently. However, since the company is a monopoly, it was necessary to control ex-refinery prices. The ex-

Dor Chemicals MTBE plant near Haifa refinery

refinery pricing system is based upon CIF Med quotations as published by Platt's in order to reflect change in the international petroleum product market.

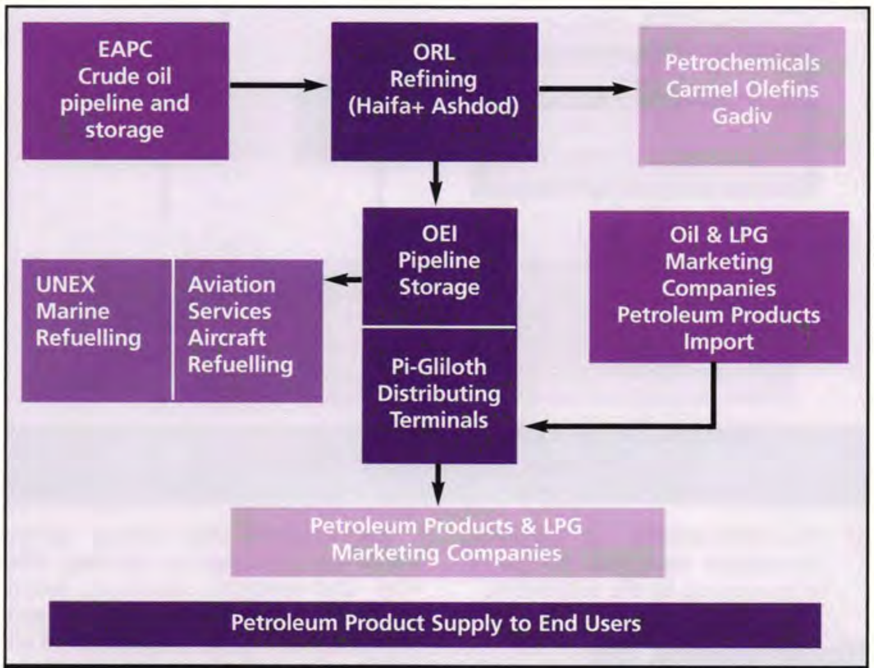

Figure 3: Current structure of Israel's oil market – the monopolies chain

Figure 4: Competitive structure of the oil market in Israel

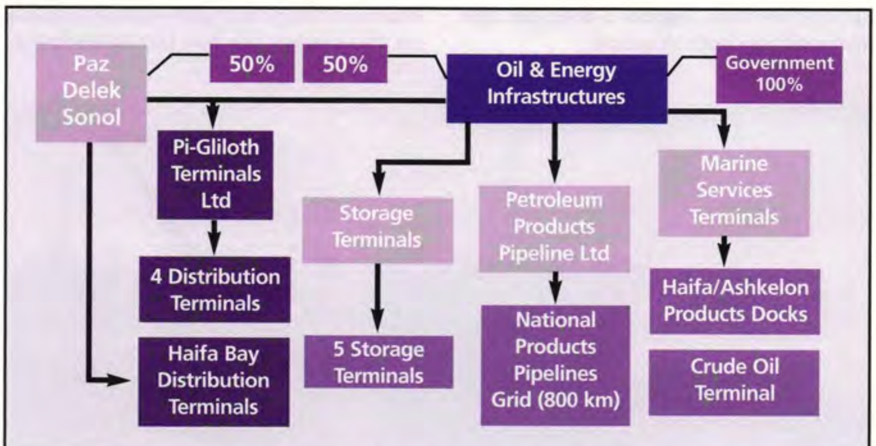

Figure 5: Current structure of Israel's infrastructure services market

Targets achieved

During the period 1988–2001 several substantial structural changes have been completed and the reform achieved part of its goals (see **Figure 2**). The government successfully switched its mode of activity from full involvement on a cost-plus basis to regulation based on a normative basis. As a result the ex-refinery product price based on Platt's Med quotations now reflects the international oil market much better than before. The same has been done with other regulated tariffs and the bulk-marketing segment is now operating in a truly competitive environment with government subsidies paid only for emergency stockpile holdings.

However, the reform has not really touched the main sectors of the oil market – the refining and infrastructure (storage and pipeline) sectors – which remain under heavy regulation and governmental ownership and are still operating in a non-competitive environment.

Key challenges

The key challenge facing the Israeli Government is maintaining the momentum of the reform process and creating a competitive environment by restructuring the refining and infrastructure sectors. The privatisation of as many companies and activities as possible in these sectors will be necessary as part of this process.

The oil market itself will also have to face a number of key challenges, including:

- The development of a domestic natural gas market by 2004. This will require major changes in the refinery sector due to the subsequent loss of market share, particularly for gasoil and fuel oil.
- More competition with imported petroleum products following the commissioning of the new marine terminal in Ashkelon.

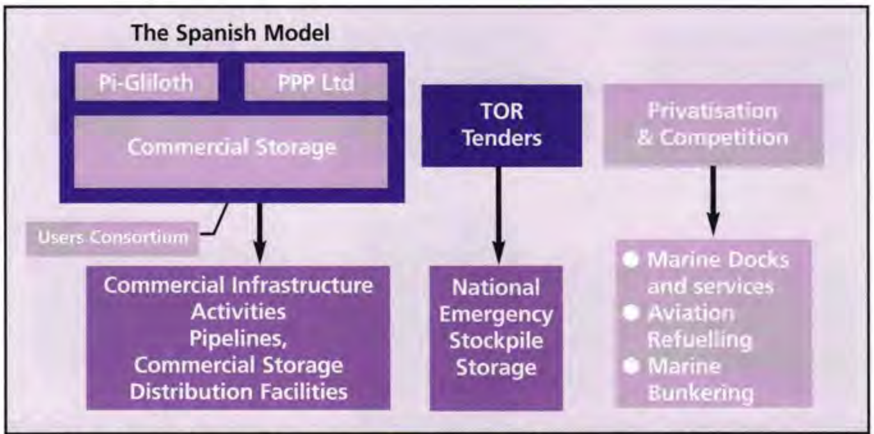

Figure 6: The way forward for restructuring the Israeli infrastructure services sector – the Spanish model

- The enforcement of European Commission standards for petroleum products by the authorities.

Restructuring the refining sector

ORL, as a monopoly, stands in the way of a competitive refining sector developing in Israel. In a bid to counter this both the Israeli Fuel Authority and the Anti-Trust Commissioner prevent the company selling its products to end-users and additionally, due to its monopolistic status, ORL is enforced to sell its products under price regulation. However, the monopoly status of ORL locks the Israeli oil market into a monopolies chain structure which is open only in the marketing segment. This structure tends to create, by definition, inefficiency and high operation costs not only in the refining sector but in all the monopolies along the chain. **Figure 3** describes this monopolies chain structure.

Restructuring the refining sector could be achieved by splitting ORL into two separate companies based on its two refineries at Haifa and Ashdod, enhancing competition in all market segments as illustrated in **Figure 4**. **Table 1** outlines the disadvantages of the current structure versus the advantages of the proposed future structure.

Restructuring infrastructure services sector

The solution for the infrastructure services sector (pipeline, storage and distribution terminals) is completely different to that proposed above for the refining sector. The differences arise from the different nature of these two markets. While the refining sector is a monopoly, but with sufficient space in the market for full business separation between the refineries, in the infrastructure services sector most of services are supplied on a national (pipeline) or regional (distribution/storage terminal) monopoly basis. Moreover, one of the major structural problems in this sector is the crossed ownership of companies (as illustrated in **Figure 5**).

Taking these structural problems into account, the restructuring of the infrastructure services sector should be based on the following key points:

- Equity re-allocation and ownership of a 'users consortium' as a means of privatisation in the core services – pipeline, storage and distribution terminal.
- Transfer of Operation Rights (TOR) tenders for operation of strategic property and emergency stockpiles.
- Introducing competition in specific fields (such as aircraft/marine refueling) where possible.

A 'users consortium' provides a way to privatise infrastructure services companies that supply services in an 'open access' environment while allowing the services or the facilities to be defined as a 'natural monopoly' such as in storage terminals or petroleum product pipelines. Such a system already operates on national scale in Spain (via CLH) (see **Figure 6**) and on a local scale in many places, for example, RRP pipelines from Rotterdam to the Rhine Valley, or the jet-fuel tanks at Stansted Airport in the UK.

Final round-up

Substantial reforms have been made in the Israeli oil market since 1988. The market has moved from a fully-controlled and planned market towards a mid-way stage where part of the market is operating in a competitive environment while some of the key sectors such refining and infrastructure services remain part of a monopolies chain.

The way to renew the momentum of reform is to deal directly with this monopolies chain. However, dealing with monopolies and their workers unions needs political power. At present it is not clear that the Israeli politicians have the power needed to resolve the remaining problems of this market.

LPG vessel in EAPC Ashkelon marine dock

** Yoav Armoni joined the Israel Fuel Authority (IFA) in 1993, working as head of the Economic Department and as Assistant to the Head of the Fuel Authority. In 1997 Yoav Armoni was nominated by the Government of Israel as the head of Israel Fuel Authority. He left the IFA in 2001 to become an independent consultant.*

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Time and cost savings with new joint integrity testing

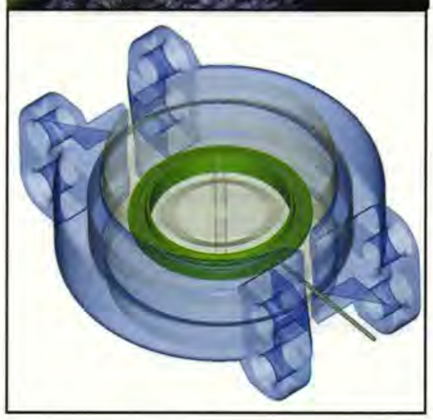
Vector International claims that its new means of testing and verifying individual joint integrity, in-situ, as the joints are installed offers 'substantial' time and cost savings.

The Reverse Integrity Test (RIT) rings can be used to test Techlok clamp connector joints either prior to, or in place of, a line leak test, explains the company. Each joint integrity test is reported to take just 15 minutes to perform. The system allows any problems to be identified at the time of installation, facilitating greater efficiency of operations. 'In particular, by avoiding the need to leak test (by fluid or gas) the full pipe to identify possible problem joints – with all the equipment, volumes, logistics, personnel, and time avoided – the RIT ring test can offer considerable savings,' states Vector.

The principle of the rings is to reverse-test (or test the 'wrong way') the lips of the seal-ring, putting a very onerous test on the seal. The RIT ring – within the hub – is used to put external pressure on the self-energising Techlok seal, in effect seeking to de-energise the seal-ring lips. The medium can be either hydraulic oil or gas, and the presence of any leak is identified by a significant pressure loss.

RIT rings are available either as separate rings – in either high strength carbon steel or 630 stainless steel – or an an integral part of the seal-ring, manufactured from a material to suit the base seal-ring. Separate RIT rings can be used for seal-ring sizes 46 to 140, while for all other sizes the integral RIT ring is used. Test pressures of 180 barg for an integral seal-ring, or 80 barg for a separate RIT ring, confirm the integrity of all suitable Techlok connections irrespective of design pressure rating. A further benefit is that the separate RIT ring also acts as a seal-ring carrier, thus easing installation as the joint is assembled, comments the company.

'The benefits of the RIT rings were demonstrated when they were used by Kerr McGee for the Gryphon FPSO, where long lengths of flexible pipe were being changed out, to avoid the need for a full length gas test,' says Vector. 'RIT rings have also been successfully applied on the BP Bruce platform to reduce both the costs and risks associated with nitrogen leak testing. When the main 10-inch ESD [emergency shutdown] valve on the gas injection riser was changed out and needed testing, the closest isolation valve was some 13 km away, so flooding the whole system with N_2He to conduct a traditional test would have required significant volumes of gas – an option that was both expensive and high risk due to the amount of stored energy. Instead, following onshore testing to both BP and HSE requirements, RIT rings



were used, allowing the valve to be tested without flooding the system, bringing time, cost and safety benefits.'

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Transforming process analysis

Circor has developed the GO MS3 modular substrate sampling system to replace the process industry's traditional use of expensive and time-consuming closed loop sampling systems. The system comprises a single block and tube architecture and a built-in flexibility that is claimed to be ideal for any gas or liquid sample conditioning system, whether single or multi-stream. The compact space-saving system's flow is external to the substrate itself.

Block system interchangeability combined with pre-welded tube assemblies and the minimisation of required substrate components significantly reduces both installed and maintenance costs and inventories, states the company. Assembly and training times are also reported to be reduced, with only a single, easy to use assembly tool required.

The manufacturer states that unlimited multi-stream and block configurations easily adapt to any system schematic, while an elastomeric seal on

the external flow path provides hassle-free troubleshooting. Suitable for use with vapour, gas or liquid, systems come with a complete set of surface mount components.

The maximum working pressure is 250 kg/cm^2 (3,600 psi). System temperature range depends on material specification with standard Viton® and optional Teflon® or Kalrez®.

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e: **circor@circor.co.uk**

Animated brochure

Smith Flow Control is producing a series of animated brochures that demonstrate graphically how its range of process safety and valve operating products – such as the Flexi-Drive and Easi-Drive – can help operators reduce accidents and increase efficiency.

They contain all the information found in a conventional brochure but, by providing moving images of the products in use as well as the corresponding effects they have on valves and actuators, they are much more effective at demonstrating the process in clear, step-by-step way.

The brochures are being released on a monthly basis, with a CD-Rom of the full set due out in spring 2003.

If you would like more information about the company and the new brochures you can register by e-mailing sales@smithflowcontrol.com **or by telephoning +44 (0)1376 517901. Smith Flow Control will keep you informed of developments and send the full CD-Rom when it is released.**

UK first for standard leak calibration

Sira Test and Certification has introduced a new facility for the calibration of standard leaks, claimed to be the only one of its kind to receive accreditation from the UK Accreditation Service (UKAS).

A 'standard' leak is essentially a reservoir of known gas with an outlet via an element that allows a nominally fixed throughput of gas molecules. The most common types are helium leaks where the element is a quartz capsule. The throughput of molecules in this case depends on a number of factors – the largest of which is the helium concentration gradient across the quartz capsule. Assuming this and the other factors can be determined with an appropriate measurement uncertainty, then the leak can be used as a transfer standard to calibrate helium leak testing apparatus. This then allows for industrial leak detection measurements to be made in accordance with international quality standards (ie with demonstrable measurement traceability).

Working in conjunction with DERA under a contract from the DTI, Sira has built a suite of standard leak calibration facilities to accommodate the UK's traceability needs. Some of these are already under Sira's UKAS scope of accreditation in respect of ISO/IEC 17025. The others are on course for accreditation in early 2003.

Sira's current accredited facilities cover the calibration of standard helium leaks in the range 10^{-6} to 10^{-8} mbar l/s. Calibration is achieved using a comparison technique based around a mass spectrometer against reference leaks that were calibrated in Germany by PTB. Uncertainties as low as 5% can be quoted depending on the exact value of the leak being calibrated, says Sira.

Additional facilities have also been developed to increase the range, such as a primary 'pressure rise' technique, which allows for gases other than helium. The facilities will also include the capability to determine the thermal dependence of the leak element – a significant factor for many types of leak.

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F: +44 (0)20 8468 1807
e: test+cal@siratc.co.uk
www.siraservices.com

Low cost potato-based drilling additive

Dubai-based GCC Starch Company has unveiled IsoFloc 17, a low-cost, high-performance potato-based drilling fluid additive. Claimed to be compatible with all drilling fluids in temperatures up to 120°C and with a high tolerance to monovalent and divalent salts, the low viscosity fluid loss reducer is reported to exceed the specfications of OCMA DFCP5 and API 13A, section 11.

Until recently potato starch-based drilling fluid additives had the disadvantage of rapid thermal degradation, breaking down the polymer chains at high temperature and long exposure to these temperatures. Recent developments however have solved these problems, providing drilling fluid additives with both high thermal resistance and low degradation rates.

IsoFloc is delivered from GCC's strategically located warehouse in Dubai and the company reports that its 'one product, one market' philosophy enables it to deliver the additive at 'signficantly lower prices than conventional products'. Furthermore, the company claims that application of IsoFloc 'will not only reduce drilling costs, but also provides the technology to extend operations at even greater depths. The growing future liability for environmental damage demands more environmentally friendly products, even in the most remote locations, which will make the starch-based products even more attractive.'

e: **info@drillingstarch.com**
www.drillingstarch.com

Setting new standards in titrator versatility and ease of use

The new Cou-Lo Compact Karl Fischer titrator from GRScientific has a footprint measuring just 245 x 250 mm, a built-in high speed printer, 10 user programmable methods and an 'ACE' (automatic compensation of errors) control system on which a patent is pending. Claimed to offer 'ultimate versatility and ease of operation' the titrator results are available in ppm, mg/kg, % and µg water.

Supplied complete with all necessary glassware, reagents, calibration certificate and a two-year guarantee, the Cou-Lo Compact complements the Cou-Lo Trans and Cou-Lo Select titrators also manufactured by the company.

T: +44 (0)1525 404747
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www.grscientific.com

NEW Publications

Energy Price Risk*

Tom James (Palgrave Macmillan, Houndmills, Basingstoke, Hampshire RG21 6XS. T: +44 (0)1256 329242; F: +44 (0)1256 812521; e: **mdl@macmillan.co.uk***;* **www.macmillan-mdl.co.uk***) ISBN 10403903409. 419 pages. Price (hardback): £120.*

This book acts as a guide to optimising company performance by using the correct price risk strategies and tools. It is designed to help the reader put in place the management controls and reporting structures necessary to ensure that a company's hedging and trading programme achieves its goals and does not add unexpected or unwanted risk to the firm. The publication includes a wealth of practical examples and covers the full spectrum of the energy complex, including crude oil, petroleum products, natural gas, LPG/LNG and electricity.

Natural Gas in Asia: The Challenges of Growth in China, India, Japan and Korea*

Edited by Ian Wybrew-Bond and Jonathan Stern (Oxford Institute for Energy Studies (OIES), 57 Woodstock Road, Oxford OX2 6FA, UK. T: +44 (0)1865 311377; F: +44 (0)1854 310527; e: **publications @oxfordenergy.org***) ISBN 0197300294. 313 pages. Price (hardback): £39.50.*

The period to 2020 will be crucial to the Asian gas markets as it will determine whether natural gas can become an important fuel in the emerging energy markets of China, India, Japan and Korea. This book seeks to identify obstacles that frustrate the growth of gas utilisation in these major Asian countries. Potential demand is considerable, and significant supply sources exist in Russia, Central Asia and the Middle East. Yet domestic and international political factors, market imperfections and difficult issues associated with the transport of gas over long distances (whether by pipeline or LNG) pose challenges to gas developments. The specific problems that vary from country to country are carefully assessed in the book by six acknowledged experts.

Assessment of Personal Inhalation Exposure to Bitumen Fume*

(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***). 31 Pages. Available as a free downloadable Adobe pdf from Concawe's website at* **www.concawe.be**

In 2000 a new occupational exposure limit was issued by the American Conference of Governmental Industrial Hygienists (ACGIH) for bitumen fume defined as the benzene-soluble fraction of inhalable airborne particulate matter. The requirement to sample inhalable particulate matter was adopted in response to a new European standard for biologically relevant airborne particulate. The ACGIH guideline is used in a number of European countries. This report (number 7/02) reviews issues associated with inhalable particulate matter exposure assessment as it relates to bitumen fumes, including comparative studies of old and new methodologies. Practical considerations, on the basis of application of a recommended new methodology are discussed and a detailed method provided as an appendix.

* *Held in IP Library*

Latest from the Library

YOUR OFFICE AWAY FROM HOME

Complete API reference set

The American Petroleum Institute (API) has kindly supplied the IP Library with copies of all their published documents, enabling us to now offer a complete reference set of up-to-date API standards, publications and recommended practices. We also hold copies of most previous API editions.

New Editions to Library Stock

- *Assessment of personal inhalation exposure to bitumen fumes: Guidance for monitoring benzene-soluble inhalable particulate matter.* C Bowen and J Urbanus. Concawe, Brussels, Belgium, 2002.
- *Britain's offshore oil and gas.* 2nd Edition. Fred Dunning, Ian Mercer, Pat Raylor, Christine Woodward and David Stewart. Edited by Steve Harris, Fiona Bridgeman and Trisha O'Reilly. UK Offshore Operators Assocation; Natural History Museum, London, UK, 2002. ISBN 1903003157.
- *CIS and East European energy databook.* 2nd Edition. David Cameron Wilson. Eastern Bloc Research, Newton Kyme, North Yorkshire, UK, 2002.
- *Decision analysis for petroleum exploration.* 2nd Edition. Paul Newendorp and John Schuyler. Planning Press, Aurora, Colorado, US, 2000. ISBN 0966440110.
- *Energy map of Algeria 2002.* Petroleum Economist; Sonatrach, London, UK, 2002. ISBN 1861861281.
- *Oil and gas – Crisis and controversies 1961–2000. Volume 2: Europe's entanglement.* Peter R Odell. Multi-Science Publishing, Brentwood, UK, 2002. ISBN 0906522188.
- *Technical progress and profits: Process improvements in petroleum refining.* John L Enos. Oxford Institute for Energy Studies; Oxford University Press, Oxford, UK, 2002. ISBN 0197300235.
- *Energy policies of IEA countries: The United Kingdom 2002 review.* International Energy Agency, Paris, France, 2002. ISBN 9264197702.

Contact Details

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- **Library holdings and loans queries to:**
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- **LIS management queries to:**
  Catherine Cosgrove, Head of LIS, +44 (0)20 7467 7111
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  Sally Ball, IFEG Secretary, +44 (0)20 7467 7115

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Visit our website at **www.petroleum.co.uk**

Membership News

NEW MEMBERS

Mr O G Awobiyi, Nigeria
Mr G P B Balfour, Hampton
Mr A K Bhan, Hindustan Petroleum Corporation Ltd
Mr S Conway, CMP Products
Mr J Corray, KPMG Corporate Finance
Mr G Davidson, Houghton-le-Sprine
Mr S A Dewar, ChevronTexaco
Mr D Doory, Warwick
Mr E Enodien, Aberdeen
Mr C Graham, London
Mr J B Gregory, Milltimber
Mr L A Hayden, Brentwood
Mr T U Islam, Shell Oil Products East
Mr J Neil, MatrixC Ltd
Mr A Pont, Ergonomics Engineering Ltd
Mr R Reynolds, Korn Ferry International
Mr R M Savage, Bank of America NT & SA
Mr R Shoylekov, Cadwalader Wickersham & Taft
Mr M R Stephenson, Morpeth
Mr D Y Sung, MSI Inc
Mr A Tomb, Acordis UK Ltd
Dr B Wood, Kinrosshire
Mr I Xenitides, Fitch Ratings Ltd

STUDENTS

Ms O M Opeyemi, London
Mr W Young, Durham

Branch Activities

LONDON

Contact: *Ian K Robinson, T: +44 (0)1932 783774*

18 Feb: 18.15: *Refinery Energy Efficiency,* by Dr Zoran Milosevic and Ms Lesley Owens, KBC Process Technology Ltd

OBITUARY

Jean-Marie Gilles MInstPet (1940–2002)

It is with great sadness that we have to announce the death of Jean-Marie Gilles of Petrofina, Brussels, after a brave struggle with cancer. Jean-Marie joined Fina Marine in 1966 following graduation from the Higher School of Navigation in Antwerp and service aboard a sailing training ship and on a dry cargo liner operating in the West Africa and South America. After two years as a deck officer on a crude tanker he was appointed as Mediator to assist with development of a new crude oil supply programme in Zaire. In 1973 he returned to Brussels to create and manage a Loss Control Team, later rising to the position of Director.

Fina, through Jean-Marie, was a very early member of the IP's PM-L-4 Marine Oil Measurement Database Panel. Jean-Marie had been Vice Chairman of the Panel for three years and was Chairman Elect when his illness struck in 1999. He will be very much missed by all his colleagues at the IP and our sympathy goes out to his friends and family, particularly Jacqueline.

EVENTS Forthcoming

FEBRUARY 2003

5–6 **London**
UVDB Live – Bringing Together the Utility Community
Details: Achilles Information Limited
T: +44 (0)1235 861118
F: +44 (0)1235 838096
e: **uvdblive@achilles.com**

6 **Paris**
Panorama 2003 – Energy, Oil, Natural Gas, the Automobile, the Environment
Details: Institut Francais du Petrole
T: +33 1 47 52 60 00
F: +33 1 47 52 70 00
www.ifp.fr

6–7 **Houston**
Value-At-Risk for the Energy Industry – Training
Details: Energy Power Risk Management Training
T: +44 (0)20 7484 9898
F: +44 (0)20 7484 9800
e: **conf@riskwaters.com**
www.eprmtraining.com

10–12 **Louisiana**
Underwater Intervention 2003
Details: Association of Diving Contractors International
T: +1 281 893 8388
F: +1 281 893 5118
www.adc-usa.org/

10–11 **London**
E&P Data & Information Management
Details: SMI Energy Conferences
T: +44 (0)20 7827 6000
Fax: +44 (0)20 7827 6001
www.smi-online.co.uk/

10–11 **London**
Petroleum Trading and Cargo Shortages
Details: Abacus International
T: +44 (0)1953 497099
F: +44 (0)1953 497098 or
+44 (0)870 052 2235
e: **information@abacus-int.com**

11–12 **London**
SCADA – Supervisory Control and Data Acquisition
Details: IBC Conferences
T: +44 (0)1932 893851
F: +44 (0)1932 893893
e: **cust.serv@informa.com**

11–12 **London**
Tanker Operations in the 21st Century
Details: Tanker Operator Magazine
T: +44 (0)20 7510 4934
F: +44 (0)20 7510 2344
e: **conference@tankeroperator.com**

11–14 **London**
Mechanics and Operations of Oil Trading
Details: Institute of Petroleum
e: *nwilkinson@petroleum.co.uk*
www.petroleum.co.uk

11–14 **France**
International Gas Economics Seminar
Details: Institut Francais du Petrole
T: +33 1 47 52 60 00
F: +33 1 47 52 70 00
www.ifp.fr

12–13 **London**
Petroleum Trading and International Law
Details: Abacus International (see entry for 10–11 Feb)

12–14 **London**
Benchmarking – Financial Performance Management in the Oil Business
Details: Institute of Petroleum
e: *nwilkinson@petroleum.co.uk*
www.petroleum.co.uk

13–16 **London**
Understanding Global Energy Supply Logistics
Details: Institute of Petroleum
e: *nwilkinson@petroleum.co.uk*
www.petroleum.co.uk

17–20 **London**
IP Week 2003
Details: Institute of Petroleum
e: *events@petroleum.co.uk*
www.ipweek.co.uk

A more comprehensive listing of events for February is available on the IP website *www.petroleum.co.uk*

MOVES People

Petroleum Geo-Services has announced that founder **Reidar Michaelsen** has stepped down as Chief Executive Officer but remains on the Board; its other Directors are **Jens Ulltveit-Moe**, Chairman; **Svein Rennemo**, Chief Executive Officer; and **Geir Aune, Thorleif Enger, Gerhard Heiberg, Marianne Johnsen, Rolf Erik Rolfsen** and **Endre Ording Sund**, Board Members.

The Chief Operating Officer of Amec's Oil, Gas and Petrochemicals operations, **Mike Straughen**, has taken over from **Paul Barron** CBE as Chairman of the Energy Industries Council. During his two-year appointment, and in addition to his responsibilities for Amec, Straughen will head the Council's Board of Directors, which is responsible for formulating and approving policy, and guiding the financial, technical and marketing sub-committees.

Weatherford International has named **Stuart Ferguson** as President of Weatherford Completion Systems division, and **David Colley** as Vice President in charge of Weatherford's Global Manufacturing Operations.

Morten Buchgreitz is the Manager of the new Financing and Business Risk Management unit at Dong of Denmark. He was previously a partner at KPMG Consulting.

Ryder Scott Company of Houston announces the following promotions: **Joe Magoto, Larry Nelms, Guale Ramirez, Fred Richoux, Dean Reitz, Ron Rhodes** and **Fred Ziehe** to Managing Senior Vice Presidents; **Joe Blankenship, John Hamlin, Gene Presley** and **Bob Wagner** to Senior Vice Presidents; and **Tom Gardner, Pat McInturff** and **Tim Torres** to Vice Presidents. **Mark J Ichara** has joined the company as a petroleum engineer.

The John Wood Group has announced that **David Baillie** has been appointed Chief Executive of Wood Group Gas Turbine Services. Baillie joined the group from Schlumberger where he has been President of Schlumberger Sema for the past 18 months. He previously held a wide range of senior management roles in the company's oil and gas activities in the North Sea, Far East, Middle East and the US.

Carl Vincent has been appointed Business Development Manager at Pipeline Induction Heat. Vincent has over 12 years' experience in specialist pipeline installation contracting.

The BG Group has appointed **Dave Roberts** as Executive Vice President and Managing Director, Eastern Hemisphere. Roberts joins the Group from ChevronTexaco where he was adviser to the Vice Chairman of the Board, primarily focused on corporate strategy. His new responsibilities cover BG's operations in the Eastern Hemisphere, including the core areas of Kazakhstan and India.

The Board of BP has announced that **Rodney Chase** will retire from the company on 23 April 2003. He will relinquish his role as Deputy Chief Executive with immediate effect but will remain on the Board as Senior Adviser to **Lord Browne** until his retirement. **Richard Olver** succeeds him as Deputy Chief Executive and will hold accountability for health, safety and the environment, human resources management, marketing, technology and digital business. He will have regional responsibility for Europe (including Russia), the Middle East, Africa and the Americas.

The Society of Petroleum Evaluation Engineers (SPEE) is pleased to announce the following new officers for 2003: President, **Mark Doering**; Vice President, **Charles Gleeson**; Secretary/Treasurer, **Daniel Olds**. The SPEE has also appointed the following Board Members: **Ed Butler, Tim Smith** and **John Wright**.

Dana Petroleum has announced that **Graham Stewart** has been appointed as the full-time Chief Executive of Faroe Petroleum, the new UK-registered holding company of Føroya Kolvetni. He has resigned from his position as Commercial Director with Dana.

Petroleum Geo-Services has announced that Board Member **Endre Ording Sund** has stepped down. This is as a result of Mr Sund assuming a key position in Orkla Enskilda Securities.

The Boards of BHP Billiton and BHP Billiton plc have appointed **Charles (Chip) Goodyear** as Chief Executive to replace **Brian Gilbertson** who has resigned as Chief Executive and Director. Goodyear joined BHP in 1999 as Chief Financial Officer, has been Chief Development Officer for the BHP Billiton Group since June 2001 and was appointed an Executive Director in November 2001.

Kim Kronstedt has recently been appointed President of Fortum Energy Solutions. Kronstedt has enjoyed a 16-year career at Fortum in roles such as business development and engineering activities within the company's oil refining unit.

Furmanite engineer **Adam Thistlethwaite** has been awarded the IMechE Best Student of the Year Award for outstanding grades and the commitment to his BEng (Hons) degree in Mechanical Engineering at the University of Central Lancashire.

Mark Aspinall has become a Partner in shipping and commodities law firm Waterson Hicks. Aspinall joins together with his team consisting of Tim Baker and Julian White who are well known in the sectors of shipping and oil trade litigation and energy joint venture and project works.

NEXT MONTH'S FEATURES...

The March 2003 issue of *Petroleum Review* will feature a round-up of IP Week 2003, including summaries of the main speeches, conference and seminar highlights, an exhibition review and all the latest news from what is one of the main calendar events in the oil and gas industry. It will also include a review of the European downstream sector by analyst Wood Mackenzie, the latest developments in the seismic arena and a look at the oil and gas sector in Latin America and the Caribbean. Accompanying the March issue will be our annual *Retail Marketing Survey*, which provides a comprehensive, statistical review of the UK service station market. *RMS* feature articles will include a look at biofuels and hydrogen-powered vehicles, C-store developments, technology drivers and comment from key players in the market.


2
IN
1
OIL
LONDON TO
PORT HARCOURT
TWICE WEEKLY
STARTING 25TH FEBRUARY