Petroleum review

SEPTEMBER 2001

North Sea

- Entering the end game?

Subsea

- Pushing back the technological boundaries

Caspian

- Tengiz – gamble pays off

Brazil

- Exploration glimmers in energy sector gloom

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

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover: BP's Tambar platform in the North Sea
Photo courtesy: BP Amoco Norge

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ROUNDUP From the Editor

Good discovery in 2001 – but is it enough?

In late July the *Wall Street Journal* ran a somewhat alarmist article entitled 'Oil giants struggle to spend profits amid shortage of exploration sites.' The basic thesis was that the largest companies were finding it hard to spend their profits to replace reserves.

It therefore seems appropriate to examine how successful the major oil companies have been in terms of exploration in 2001. Examining all the stories run in the News in Brief Service on our website (**www.petroleum.co.uk**) gives some indication of this year's success.

Earlier in the year, Robertson Research produced its annual review of the oil companies listing of the most prospective countries. This year's top ten ran: Libya, Iran, Algeria, Australia, Brazil, UK, Egypt, Iraq, Angola and Indonesia.

Before examining individual companies it is worth examining how Robertson's top ten have performed so far this year. Libya has seen little discovery apart from Repsol-YPF's find in the Murzuk Basin in block NC186. Iran has positively starred with the recent 400mn barrel Tossan field discovery onshore and the earlier Dasht-e-Abadan find offshore – claimed to be as big as Azadegan (recoverables of 4–6bn barrels). There has also been the 40bn cm Ramhormoz gas discovery close to the Iraqi border. For Algeria, Sonatrach has reported the discovery of an oil field in the Qued Myn Basin and this, with the formal go-ahead for BP's massive In-Salah gas export project (see p6) should trigger renewed interest.

Australia has made a series of discoveries, the most notable being OMV's Audacious discovery in the Timor Sea whose 9,100 b/d on test is the second highest ever for the region. Chevron's WA-267-P gas discovery in the Gorgon area of the NW Shelf enhances development prospects for the area. In Brazil Petrobras has recently reported some small finds totalling 130mn barrels but, for the moment, the Campos Basin appears well defined and the Santos Basin effectively untried but prospective.

The UK is covered in our annual review (p13). Production is in steady decline, having run 10% below year earlier levels during 1H2001 before plunging to 18% in June as annual maintenance took its toll (see p5). Companies are scrambling to develop new finds, old finds and field extensions to load up production infrastructure and delay abandonment. Discovery in 2001 has been good, though still a small fraction of replacement volumes (see p24). The Buzzard find is probably the largest oil find since Schiehallion in 1993.

Egypt is another country in sustained oil production decline that has had a good discovery record in 2001 with large gas finds offshore the Nile Delta and oil discoveries in the Western Desert and the Gulf of Suez.

Iraq has not so far reported any discoveries in 2001. Angola continues to produce major discoveries – one for ExxonMobil and two for BP – but the rate is clearly slowing. Indonesia, the last of the top ten, has reported only limited discovery, most notably a Unocal field offshore East Kalimantan and Premier's (now Agip) Ujung Pankak 450bn cf gas field offshore East Java.

Among the mega-majors BP is the clear exploration star. Finds include a 500bn cf gas field – Fayoum – offshore Egypt; a 600bn cf gas field – Libra – offshore the Nile Delta; the Claw oil find close to BP's Schiehallion field west of Shetlands; a 10,000 b/d and a 3,000 b/d find as Gupco in the Gulf of Suez; the 180mn boe Cashima gas field offshore Trinidad; the 35mn barrel Palm field, a satellite to Kuparuk in Alaska; and finally, two 5,000 b/d finds in block 18 offshore Angola.

The soon to be merged Chevron–Texaco has, as Chevron, the 10,022 b/d Tombua find in block 14 offshore Angola; the 3,173 b/d La Yessara find in Rio Negro Norte in Argentina; and the 3,200 b/d, block B8/32 Kung discovery offshore Thailand; as well as the gas find in the Gorgon area offshore Australia. Texaco contributes three Gulf of Mexico finds – North Tern, Oscar and a wildcat find in Vermilion Bay.

TotalFinaElf reported the 3,400 b/d West Kashagan find and the 6,000 b/d block XX find in Bolivia. Shell discovered the Bonga South-west field – a discovery sufficiently large that it will be a separate development from Bonga. Shell, with ExxonMobil, had the 11bn cm gas find in block K/15 in the Netherlands, and with BP, made two block 18 discoveries offshore Angola. To date, ExxonMobil has only reported the Mbulumbumba-1 find in block 15 offshore Angola.

History will record whether this impressive list of discoveries is enough to maintain the position of the mega-majors or whether lack of reserves will trigger another merger and buying spree.

Chris Skrebowski

e-world

The Oxford Princeton Programme (provider of training solutions to the global energy industry and a division of FAME Information Services) has unveiled its first 'Industry Basics' web-based training (WBT) course – 'An Introduction to the Oil Industry' – available at **www.PrincetonLive.com**,

Emerson Process Management has unveiled e-fficiency™, an Internet-based service that delivers information about the performance of process plant equipment directly to a web browser. Designed specifically for personnel involved with maintenance, reliability or rotating equipment **www.e-fficiency.com** is said to provide easy access to a comprehensive set of performance results, customised reports and graphical representations for monitoring plant equipment performance.

B2B e-commerce company Ventro Corporation is to acquire privately held NexPrise, a provider of collaborative commerce solutions based in Santa Clara, California, for $27mn.

IntercontinentalExchange has introduced a group of power and gas market price indices on its exchange at **www.intercontinentalexchange.com** An index history is also available.

A correct action of the driller at the onset of stuck pipe can make the difference between a simple operation or an expensive remedial action. Stuck Pipe is a simple programme that asks the user for information regarding movement of the drill string immediately prior to becoming stuck, such as motion, rotation and circulation. Based on this information, the programme determines the most likely sticking mechanism and the best course of action. Developed by Randy Smith Training Schools and Datalog, a complementary download (2.75 MB) is available at **www.wellwizard.com/stuckpipe.html**

The publication Oil, Gas and Petrochemical Export Opportunities in Northwest Europe has been changed to an online searchable database on the Trade Partners UK website at **www.oandgexport.com** in a bid to provide more timely information. Project updates will be distributed as they occur, forwarded to users via an e-mail alert. The site will be available to all notified customers without restricted access for a trial period only; after this, online registration will be required by all users.

For those looking for links to oil and gas companies and related organisions, surfers can try accessing **www.thebigproject.co.uk** via a drop down button entitled 'Engineering.' The site also holds general information on everyday issues such as travel and telephone directories.

In Brief

UK

TotalFinaElf has been given the green *light by the UK Government to develop the £145mn Otter field in North Sea block 210/15a. The field is to be developed as a subsea tie-back to project partner Shell Expro's Eider platform. Start-up is slated for 4Q2002, with production expected to plateau at 30,000 b/d.*

French contractor Bouygues Offshore is *reported to have put its UiE Clydebank construction yard up for sale, stating that the current fabrication market does not justify keeping the yard open.*

UK Energy Minister Brian Wilson has *launched the 10th UK Round of Landward Petroleum Licensing, inviting applications for all unlicensed acreage in Great Britain above the Mean High Water Mark. He has also invited applications for three North Sea blocks – 30/24, 42/25 and 43/21 – one of which contains the abandoned Argyll field. Applications for both the onshore and offshore must be submitted by 31 October 2001.*

BG is understood to have put out to *tender a contract for the fabrication of a 600-tonne platform for the Minerva field, part of the company's Juno project in the southern North Sea which is due on stream in 4Q2002.*

SLP Engineering is reported to have *been awarded the engineering, fabrication and installation contract for the accommodation platform for Conoco's CMS III project in the southern North Sea. Dutch company HBG is to fabricate a compression module for the Murdoch platform, also part of the CMS project.*

Europe

BP is reported to have submitted a *plan for development and operation (PDO) of the Valhall flank project to the Norwegian authorities. It is proposed to boost output from the producing Valhall field via two wellhead platforms tied back to the main production complex. It is understood that the company hopes to produce a further 127mn boe from the 1Q2003.*

Statoil has submitted a plan for devel- *opment and operation (PDO) of its North Sea Kristin gas and condensate field. Due onstream in 3Q2005, it is proposed to develop the field via 12 subsea wells tied back to a floating production*

Dispute over Norwegian North Sea gas sales

Fortum Petroleum reports that it, together with 28 other gas producing companies on the Norwegian Continental Shelf, has received a Letter of Objections from the DG Competition of the EU Commission concerning the joint sale of Norwegian gas through the Gas Negotiation Committee (GFU). A similar letter was sent to Statoil and Norsk Hydro in mid-June (see p22). In the letter, the Commission states that the foreign licencees have also breached EU competition laws – in the past no company has been allowed to sell its Norwegian gas directly, instead, all gas sales had to be channelled through the GFU founded by Statoil and Norsk Hydro.

Fortum commenced gas production in Norway from the Åsgard field in October 2000. The sales value of this gas amounted to some 80mn euros by end-2001. Some associated gas has also been produced in connection with Fortum's Norwegian oil production that began in 1993.

The companies have been given three months to respond. Fortum states that its stance 'will be based on the fact that the Norwegian regulations have obliged all companies to channel their gas sales through the GFU.'

New Timor Gap treaty under debate

The Australian Government recently expressed disappointment over Phillips Petroleum and its co-venturer's decision to defer a decision on the proposed 500-km gas pipeline from the Bayu Undan field to Darwin, reports *Jeff Crook*.

The deferral arose following uncertainty over the legal and fiscal regime in the Timor Gap. An Australian Government statement said that it was 'unfortunate' that just hours after agreeing the Timor Sea Arrangement, the UN Transitional Administration in East Timor (UNTAET) and representatives of the local people had used its taxation powers to recover an additional $500mn in tax from companies.

The proposed pipeline would have created a 'gas hub' in the Timor Sea which would initially convey gas from the Bayu Undan field and would later have carried gas from Greater Sunrise and possibly the Evans Shoal fields. The combined gas reserves of these fields are currently estimated to exceed 22tn cf, with Greater Sunrise volumes (9.16tn cf) similar in scale to the reserves available at the time that the North West Shelf LNG project was committed in 1985. Bayu Undan has gas reserves of over 3tn cf of gas.

Under the new treaty, initialled in Dili on 5 July 2001, East Timor would receive 90% of the revenue stream from a 'Joint Petroleum Development Area' (JPDA) whilst Australia would receive 10%. This compares to the previous 50:50 split. The new treaty also unitises Greater Sunrise, which straddles the boundary, allocating 20% of the field to the JPDA and 80% to Australia.

It was anticipated that East Timor would receive substantially more than A$7bn in revenue from existing and planned developments in the 20-year period from 2004 under this treaty. Australia would receive A$1bn during this same period, together with extensive downstream benefits. The new treaty has a duration of 30 years.

Typhoon onstream and under budget

The Chevron-operated Typhoon field in the Gulf of Mexico has come onstream just 18 months after project approval and under its original $256mn budget.

Located in Green Canyon blocks 236 and 237, the field development comprises the subsea completion and tie-back of four existing appraisal wells to a mini tension leg platform (TLP) based on the Atlantia SeaStar™ design. Depending on well performance, output is expected to reach about 40,000 b/d of oil and 60mn cf/d of gas during 4Q2001.

The field was granted Deepwater Royalty Relief in December 2000 by the US Minerals Management Service (MMS), which allows for royalty exemption on the first 87.5mn boe from Typhoon under certain oil pricing market conditions. Field life is put at between five and eight years.

Typhoon partners are Chevron (50%) and BHP Billiton (50%).

Gas gathering offshore Nigeria

A consortium of Stolt Offshore and DSNL (a subsidiary of the Adamac group of companies in Nigeria) has been awarded a contract from Shell for the pipelay associated with the construction of the Shell Offshore Gas Gathering System (OGGS) in Nigeria. The value of the contract to Stolt is put at $135mn.

Construction of the OGGS involves the installation of 88 km of 24-inch diameter pipeline from Forcados/Yokri, as well as 18 km of 16-inch pipeline from South Forcados, to the Bonga OGGS riser platform. A 264-km, 32-inch trunkline, including 8 km onshore, to connect the Bonny Island LNG plant, will also be installed – claimed to be the largest trunkline to be constructed offshore West Africa to date. Pipelay operations are slated to begin in 3Q2002.

Adamac is to construct the onshore receiving terminals, as well as providing pipe coating, storage and loading services from its base in Port Harcourt.

Lukoil plans

Lukoil plans to produce 100mn t/y of crude oil and 100bn cm/y of natural gas by 2006–2007, according to UFG. While the growth in production is in line with previous announcements and UFG's expectations of 4% production compound annual growth rate (CAGR) over the next decade, the ambitious gas output projections are definitely above expectations and may be hard to implement, comments the analyst.

Lukoil currently produces less than 6bn cm/y of associated gas, but it possesses substantial reserves in Kazakhstan and the Caspian Sea, as well as newly-acquired properties in the Yamal-Nenets district. As a result, UFG predicts that the company could theoretically achieve between 50% and 80% CAGR in the natural gas segment. 'The economic viability of this programme is fully dependent on the liberalisation of the domestic gas market as well as on access to export pipelines, comments UFG.

Camisea deal for Paragon

Pluspetrol Peru has selected Paragon Engineering Services of Houston to project manage the development of the Camisea upstream facilities in the Peruvian jungle in a contract valued at $14mn.

Due onstream in December 2003, Phase 1 of the project is forecast to produce 400mn cf/d of gas and 20,000 b/d of condensate.

Paragon's project management role covers not only the production facilities at the Camisea field, but also two in-field gas gathering pipeline systems from the development wells to the Camisea site processing plant and two gas injection pipelines.

It will also manage the design and construction of a natural gas liquids (NGL) fractionation facility and marine terminal at the proposed Pampa Clarita site on Peru's Pacific Coast.

Separate contractors will design and built two trans-Andes gas and liquid pipelines to the Pacific Coast.

North West Shelf LNG signs Japanese deals

The North West Shelf LNG Sellers have agreed key terms with Chubu Electric Power Company for the long-term sale and purchase of 0.6mn t/y of LNG beginning in 2009. Chubu Electric, a long-term customer of the North West Shelf, is Japan's third largest electric power utility and the second largest consumer of LNG.

The agreement with Chubu follows recent Letters of Intent with other Japanese customers:

- Tokyo Gas and Toho Gas on 22 September 2000 for the supply of 1mn t/y of LNG, starting 2004.
- Osaka Gas on 16 January 2001 for the supply of 1mn t/y of LNG, starting 2004.
- Tohoku Electric on 5 February for 0.4mn t/y of LNG, starting 2005.
- Kyushu Electric Power on 28 March for the supply of 0.5mn t/y of LNG, starting April 2006.

Negotiations are continuing with other Japanese customers and agreements for further LNG sales are expected to be concluded in the near future.

The six equal partners in the North West Shelf Venture are Woodside Energy (operator), BHP Petroleum, BP, Chevron, Japan Australia LNG, and Shell.

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platform. Gas will be piped via the Åsgard pipeline system, with condensate exported via a storage ship.

First oil has flowed from the Hanze field *in block F2a in the Dutch sector of the North Sea at an initial rate of 11,000 b/d. An additional production well and an injection well are to be drilled within the next few months to boost production to the planned peak flow of 30,000 b/d. By the end of the year, Hanze output is expected to account for two-thirds of the Netherlands' overall oil production.*

Enterprise Oil has sold its assets in the *Danish sector of the North Sea to Paladin Resources for $35mn plus interest. The assets include the 5,900 b/d producing Siri oil field (which has reserves put at 4mn barrels) and the Stine discovery.*

Norwegian tanker owner Navion is *understood to be exiting the FPSO leasing market following the sale of its last FPSO – the* Berge Munin *– to Bluewater. Navion will now focus its activities on tanker ownership.*

North America

Apache has announced a new gas find *on its Eugene Island block 187 in the Gulf of Mexico. The JD 2 discovery well tested at 9.6mn cf/d of gas and 184 b/d of oil.*

Spinnaker Exploration is reported to *have found gas and condensate at its Stirrup prospect on Mustang Island block 861 in the Gulf of Mexico, which tested at 21.1mn cf/d of gas and 130 b/d of condensate.*

BP is reported to have announced that its *Northstar oil field offshore Alaska is to enter production by November/December 2001 and will meet its target of 65,000 b/d by 2002. Field reserves are put at 175mn barrels of oil.*

Middle East

Five new blocks covering 26,000 sq km *have been designated for oil and gas exploration and a related tender called in July by the Syrian Oil & Mineral Resources Ministry in a bid to stem the continued fall in oil production in Syria, reports* Stella Zenkovich. *Production is forecast to fall to 530,000 b/d in 2001.*

Iran is reported to have made an oil *discovery – called Tossan – in the south*

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of the country. Estimated reserves are put at 400mn barrels.

Russia & Central Asia

Yamalgazinvest is reported to be planning *to develop the Shtokmanov gas condensate field in the Barents Sea at a cost of $25bn.*

Lukoil's Board of Directors recently *approved the acquisition of a 20% interest in the Kharyaga PSA from TotalFinaElf and Norsk Hydro.*

Asia-Pacific

The China National Offshore Oil *Company is reported to be planning to double production from its Suizhong 36-1 oil field in China's Bohai Bay to 70,000 b/d from 29,5000 b/d in 2000.*

PetroVietnam and Cuu Long joint venture *partners Conoco, Korea National Oil Corporation, SK of Korea and Geopetrol of France are reported to be planning to bring the Su Tu Den field in block 15-1 offshore Vietnam onstream in 2003/2004. Potential recoverable reserves are put at between 200mn and 400mn barrels.*

US company Unocal is reported to *have brought the Plamuk field onstream – its first oil field in Thailand – at 2,500 b/d through an early production system. The company is also understood to have leased the Sibea FSO vessel; production is expected to reach 18,000 b/d by 1Q2002 once a new platform is installed.*

Hyundai Heavy Industries is reported *to have landed the $780mn contract to build an FPSO for ExxonMobil's Kizomba project offshore Angola. Engineering work is to be subcontracted to an Amec-Fluor Daniel joint venture. The vessel will have a 2.2mn barrel storage capacity and be able to process up to 250,000 b/d of oil.*

OMV is reported to have approved *development of its Patricia Baleen gas field offshore Victoria, Australia.*

Phillips Petroleum is reported to have *put on hold the construction of a gas export pipeline for the Bayu-Undan project in the Timor Sea while stakeholders Santos, Kerr-McGee, Inpex, Petroz and Agip are understood to have agreed to defer investing in a pipeline to Darwin in a move that will also delay commercialisation of Timor*

Downward pressure on oil price

Monthly oil production from the UK Continental Shelf fell during May 2001, although revenues were up on both the month and the year, according to the Royal Bank of Scotland's latest *Oil and Gas Index*. Tony Wood, Oil and Gas Economist at the Bank said in late July: 'The price of Brent crude has fallen by nearly 20% in the past six weeks. With demand continuing to be weak and the supply situation improving there could be further pressure for prices to fall in the coming few weeks. All eyes remain on Opec, which will require to balance the current market weakness with the expectation of strengthening demand towards the end of the year. However, a production cut of 1mn b/d now seems likely at some point during August.'

Production of oil fell to 2,170,520mn b/d in May 2001, 2.4% down on the month and 2.3% below May last year. Average daily production in the 12 months to May 2001 fell by 10.3% compared with the 12 months to May 2000. Oil revenues for May 2001 averaged £43.01mn/d, an increase of 7% on the month and 28.1% on the year. Even though production is down, the higher oil price continues to sustain average oil revenues at some of their highest levels for the past decade, states the report.

There was a significant fall in monthly gas production, largely due to seasonal demand variation. May production was down by 23% on the month, although output rose by just under 1% compared with May 2000. Average daily production grew by 2.1% in the 12 months to May 2001, compared to last year.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
May 2000	2,222,686	9,089	24.15
Jun	2,436,450	8,609	30.50
Jul	2,383,944	7,531	28.90
Aug	2,339,363	7,464	31.60
Sep	2,281,516	8,080	33.70
Oct	2,247,307	10,172	30.90
Nov	2,322,296	11,621	32.80
Dec	2,399,038	11,439	26.30
Jan 2001	2,274,671	13,061	25.80
Feb	2,206,542	12,293	27.50
Mar	2,301,409	12,465	24.50
Apr	2,223,924	11,918	25.95
May	2,170,520	9,155	28.26

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Native North Americans file law-suit

The Fort Peck Assiniboine and Sioux Tribal Nation in Montana have filed a law-suit against the gas pipeline company Northern Border for $3mn in unpaid taxes, a case that could settle case law over whether oil and gas companies have to pay taxes to native north American groups when they use their land, reports *Kate Rew.*

In 1980, Northern Border received permission from the Fort Peck tribes to construct a natural gas pipeline through their 2.3mn-acre reservation in the northeast of the state. Under current law, tribes are allowed to collect taxes on non-Indian businesses under certain conditions, but, claimed the Assiniboine and Sioux' lawyers Reid Peyton Chambers, companies have interpreted some recent court rulings as enabling them to ignore these rights.

Tribal Chairman, Arlyn Headdress, said that the tax that Northern Border is refusing to pay represents approximately 25% of the Tribes' annual revenue; its value – until Northern Border's lease ends in 2011 – is approximately $13.8mn.

Smit secures Espoir FPSO contract

Smit Maritime Contractors has been awarded the installation contract for the Espoir FPSO to be stationed offshore Africa's Ivory Coast. The FPSO – which will be operated by Prosafe Production on behalf of Ranger Oil Cote d'Ivoire SARL, part of CNR International – is currently undergoing conversion at the Keppel yard in Singapore.

The Espoir vessel will have a crude oil production capacity of 40,000 b/d, a water injection capacity of 60,000 b/d and a gas compression capacity of 60mn cf for gas lift and export. Oil will be exported by shuttle tanker and gas will be exported to shore where it will be used to generate electricity.

Pictured: Smit's multipurpose offshore installation vessel *Smit Pioneer.*

First production from Brutus GoM field

Shell has brought onstream its Brutus tension leg platform (TLP) in Green Canyon block 158 in the Gulf of Mexico. Daily output is expected to peak at 100,000 b/d of oil and 150mn cf of gas by 2Q2002. Gross ultimate recovery is estimated at about 250mn boe.

The eight-slot TLP is Shell's first deepwater platform to be specifically designed to serve as a hub for future subsea developments in the surrounding area, although several of the company's platforms have been previously retrofitted to serve as hubs.

Floating LNG first

Shell has unveiled a proposal to develop Australia's Greater Sunrise gas fields in the Timor Sea via a floating LNG plant – in what is claimed to be would be the first ever use of such technology. The floating plant would be located offshore on a barge close to the planned Sunrise drilling platform. As well as manufacturing LNG, the barge would offer the option of compressing gas for delivery by pipeline to Darwin, Australia, which would support the development of new industries in the area and provide for the longer-term supply of gas to customers in the eastern states of Australia.

Shell and partner Woodside Petroleum already have a deal in place with Methanex to supply Greater Sunrise gas to a planned A$1.5bn methanol and syngas facility near Darwin.

Kyoto latest

Broad political agreement on the operation of the Kyoto Protocol on climate change has been achieved in Bonn, Germany by 186 participating nations, but without the participation of the US, writes *Keith Nuthall.*

Original targets were scaled down to ensure the participation of Japan, Canada and Australia in the deal, who secured concessions on so-called carbon sinks – they can now gain credits to emit more gases through re-vegetation and effective management of forests and farmland. Environmentalists cautiously welcomed the deal, with the Worldwide Fund for Nature claiming the new package would lead to a cut of between just 1% and 3% in emissions from 37 of the world's largest and richest countries by 2010.

In Brief

Sea gas resources. The companies are reported to be unhappy with the new fiscal regime covering the Joint Petroleum Development Area (JPDA) of the Timor Sea.

***Indian state company Oil and Natural** Gas Corporation (ONGC) is reported to be planning to develop as many as 107 small oil and gas fields (including 60 offshore projects) in which hydrocarbon reserves are put at between a total of 200mn and 250mn tonnes. Development may be via joint ventures.*

Latin America

***Chevron has announced the discovery** of a new oil field in the Rio Negro Norte block in the Argentine Province of Rio Negro. The La Yesera x-1 discovery well tested at 3,173 b/d of 53° API oil.*

***PdVSA subsidiary Bitor is reported to** have signed a deal to supply up to 6.5mn t/y of Orimulsion to Petrochina for 30 years, beginning in 2004.*

***MODEC International, a joint venture** between FMC Technologies of the US and Modec of Japan, has signed a $290mn contract to deliver an FPSO and related subsea equipment to Enterprise Oil's Bijupira-Salema fields offshore Brazil.*

Africa

***BP and state-owned Sonatrach are** understood to have signed a $2.5bn agreement to jointly develop Algeria's In Salah gas reserves. First production is expected in 2003, with an annual output of 9bn cm of gas from the El Krechba, Teg and Reg fields.*

***Texaco is reported to have announced** that its Agbami field offshore Nigeria may contain as much as 1bn barrels of oil. The field is due onstream by mid-2005, with production expected to reach 200,000 b/d by 2007.*

***The West African Gas Pipeline Project,** which is to carry surplus gas from Nigeria to Ghana, Togo and Benin, is expected to start delivering gas in 2003, reports* Stella Zenkovich.

***Sudan's Bambo oil field is reported to** have come onstream at 15,000 b/d from 11 production wells. A further 15 wells are to be brought into production before year-end, boosting output to 30,000 b/d.*

In Brief

Europe

Fortum has sold its 2% stake in Latvian *gas company Latvijas Gaze to an undisclosed buyer in a deal valued at euro 16mn.*

Statoil has posted a net 2Q2001 *income before taxes of NKr17.12bn ($1.89bn), up 40% from the same period last year.*

The Board of Coflexip Stena Offshore *is reported to have approved Technip's euro 3.5bn ($3.1bn) takeover proposal after the French company raised its cash bid from euro 193 per share to euro 199 per share.*

Saipem, a subsidiary of Italian energy *group Eni, is reported to have acquired Norwegian engineering firm Moss Maritime for $55mn and US engineering company Petromarine for $10mn.*

North America

Devon Energy is reported to be planning *to acquire Mitchell Energy for $3.1bn and the assumption of $400mn in debt. If the merger goes through, it is reported that Devon would become the second largest US independent gas producer behind Anadarko.*

Apache has posted 2Q2001 earnings *before nonrecurring items of $241mn, up 73% from $139mn in the prior-year period.*

Anadarko has posted a 2Q2001 net *income of $401mn.*

Phillips Petroleum has posted a *2Q2001 net income of $618mn and an operating income of $601mn, up from $442mn and $439mn respectively for the same period last year.*

Canadian Natural Resources has *changed the name of its subsidiary Ranger Oil to CNR International.*

US gas company Questar Corporation *is understood to be planning to acquire Shenandoah Energy for $406mn in cash and assumed debt.*

Chevron has posted 2Q2001 net *income of $1.324bn, compared with a 2Q2000 net income of $1.116bn. 1H2001 net income was $2.924bn, up from $2,160bn in the first six months of 2000.*

NEWS Industry

Shell increasing focus on gas

Posting the company's 2Q2001 results, Shell Chairman Philip Watts stated that the company is increasingly focusing on gas and LNG for its future earnings growth in its exploration and production division. The E&P division recorded adjusted earnings of $2,185mn for 2Q2001, 1% higher than the $2,153mn achieved a year ago.

Downstream Gas & Power adjusted earnings of $390mn were also reported to be a record, some 59% above those recorded for 2Q2000. Chemicals adjusted earnings of $217mn were 54% lower than in 2Q2000, mainly due to 'very difficult trading conditions.'

For the Group as a whole, adjusted CCS earnings of $3,534mn were a second quarter record and 12% higher that those achieved in the same period a year earlier. This was reported to mainly be due to improved oil products earnings of $1,035mn (an increase of 44% from 2Q2000), most notably in the US, and growth in the LNG business.

ROACE (return on average capital employed) on a CCS earnings basis for the year to 30 June 2001 was reported to be a record 21.4% compared with 16% a year earlier.

TNK takes controlling stake in Sidanco

Russian oil company TNK is reported to have acquired for $1.3bn an 84% stake in rival company Sidanco, in which BP owns 10%. The deal – which, according to analyst UFG, will make TNK the third-largest oil company in Russia in terms of equity production, behind Lukoil and Yukos – breaks a long-running deadlock over the future of Sidanco between TNK and holding company Interros. Earlier this year, TNK acquired a 40% stake in Sidanco. As part of the agreement, TNK has agreed to return Chernogorneft, Sidanco's main Siberian oil subsidiary, back to Sidanco in return for a 25% stake plus one share. BP will retain its 10% stake in Sidanco and will continue to operate and manage the company over the next three years.

TNK is also to merge its operating rights to part of the eastern Siberian Kovytka gas field to Rusia – the BP-led consortium developing the project. TNK and Interros will hold minority blocking shares of 25% plus one share, with BP increasing its stake in the project from 28% to 33%.

UN managing Indian CBM project

UNIDO, the United Nations Industrial Development Organisation is managing a major coalbed methane (CBM) project in the Jharia coal fields in the State of Jharkand on behalf of the Indian Government, the UN Development Programme and the Global Environment Facility, reports *Brian Warshaw.*

Open cast production accounted for three-quarters of India's 304mn tonnes annual production in 1999–2000, and it is the third-largest coal producer in the world. The CBM project will demonstrate the techniques for methane recovery that are specific to the Indian sub-continent. CBM could become a significant source of energy to the chemical, ceramic, glass and steel plants operating in the region.

The project will provide training and experience in identifying, designing and implementing CBM recovery, with a programme of drilling at the Moonidih and Sudamdih coal mines. The Moonidih mine has coal depths to 500 metres, while the Sudamdih mine has thick seams that follow gradients of between 25° and 40°. A database of CBM information and technology is also to be created.

Alaskan gas in the pipeline

The Grand pipeline project, carrying natural gas from Alaska to the mainland US, will cost between $15bn and $20bn according to the Alaskan gas producers consortium which includes ExxonMobil, BP and Phillips, reports *Monica Dobie.* Spokesman Curtis Thayer told Canada's *National Post* the figure includes the cost of a high-volume pipeline from Edmonton to Chicago.

While there is consensus about this part of the route, a decision on its northern portion from Prudhoe Bay, Alaska, to Edmonton, will be decided this year, he said. One option travels down the Alaska Highway, across the Yukon, into Alberta. The other requires a pipeline buried beneath the Beaufort Sea, following the Mackenzie river to Alberta.

NEWS Industry

HP world record for sea water injection pump

Sulzer Pumps is to build a prototype injection pump claimed to be capable of generating the highest sea water injection pressure ever achieved. The contract was awarded by BP for the Crazy Horse project in the deepwater Gulf of Mexico. Water will be injected at a flow rate of 338 cm/hour at a pressure of 605 bar (8,515 psi).

Initially, one prototype pump will be built and subjected to extensive mechanical testing at the Sulzer facility in Leeds, UK. This will include testing the pump in its 'end of life' condition, with running clearances that are twice those of a new pump. The pump is based on Sulzer's HPcp high-pressure barrel casing pump range. On completion of tests, three complete additional pump units will be built and the prototype converted into an operational pump. Delivery of the four units is slated for March 2003.

Optimistic findings by UNCTAD report

An optimistic long-term view of oil company prospects is found in the latest World Commodity Survey from the United Nations Conference on Trade and Development (UNCTAD), reports *Keith Nuthall*. It has suggested that oil production will surge in the next two decades and also that petroleum companies will take advantage of new technology to establish a commanding presence in renewable energy sectors.

The survey highlights projections that Opec's Middle East members 'should more than double' production of petroleum and condensates to 43.7mn b/d by 2010 and 49mn b/d by 2020, with world daily demand reaching 94.8mn barrels. It also quotes 'prospective scenarios' from Shell, saying that the company could obtain 50% of its turnover from renewable energy by 2050. Indeed, the report predicts that oil companies will diversify into electricity generation, partly propelled by the anticipated boom in gas, which the survey says will meet one-third of EU energy requirements by 2020.

BP posts record second quarter results

BP has posted a record 2Q2001 pro forma result of $3,799mn compared with $3,610mn in 2Q2000. For the half-year, the result was a record $7,925mn, compared with $6,317 a year earlier. Return on average capital employed (ROACE) was 23% in the second quarter, compared with 21% a year earlier.

The E&P division's second quarter result of $3,918mn was up by 8% on a year ago, reflecting an 11% increase in gas production, higher North American gas prices and lower exploration expense. The Group reported that it is 'on track to deliver the growth target for the year, continuing the rapid turnaround in production growth from the low point last year.'

In Gas & Power, the 2Q2001 result of $173mn – up from $114mn in 2Q2000 – was reported to reflect 'further improvement in marketing and trading.'

The Refining & Marketing sector posted a record second quarter result of $1,762mn (up 26% on the same period last year) reflecting 'higher refining margins, the Burmah Castrol acquisition, the consolidation of the fuels business in Europe and continued unit cost improvements.' However, the Chemicals' result of $9mn was down from the 1Q2001 figure of $370mn as 'margins and costs remained under pressure from high feedstock and energy prices in a period of demand weakness, and some plants suffered operational problems.' The 2Q2001 Chemicals' figure included $19mn for restructuring costs.

In Brief

***ExxonMobil has posted a 2Q2001 revenue** of $56.46bn compared with $55.96bn for 2Q2000.*

***Texaco has posted a 2Q2001 net** income before special items of $817mn, up from $641mn for the same period a year earlier.*

***Amerada Hess has posted a 2Q2001** net income of $357mn compared with income of $202mn for 2Q2000. 1H2001 net income was $694mn, up from $426mn in 1H2000.*

Russia & Central Asia

***Lukoil has unveiled a threefold increase** in net profit for 2000. The figures, reported in accordance with US accounting standards and audited by KPMG, showed net profit surging from $1.06bn in 1999 to $3.31bn and earnings per share rising from $1.69 to $4.83.*

***Surgutneftegaz has reported a 2%** decline in revenues to $2,542mn between 1H2000 and 1H2001, but a 21% increase in costs to $1,118mn, according to UFG. The 1Q2001 results showed a 5% improvement in net sales to $2,542mn.*

***Aminex has entered into a conditional** agreement to sell Aminex Production Company Limited (Apcol) to Acont Enterprises, a wholly-owned subsidiary of Lukoil, for $38.5mn (net $24.6mn after debt repayment and expenses).*

***Russia's First Deputy Property Minister** Alexander Braverman has said that the government plans to sell a 19.69% stake in Slavneft in mid-2002, reports UFG. The Minister also stated that the government had no plans to sell stakes in Rosneft or Transneft next year.*

***The Russian Government intends to** spin off the gas pipeline business from Gazprom by the end of 2004.*

***Transneft is looking at ways of** increasing Russian export capacity and has indicated that it is continuing to study a potential pipeline system from Omsk in Russia, across Central Asia and Iran, to the Arabian Gulf, reports UFG.*

Asia-Pacific

***Woodside has posted a record 1H2001** operating profit of A$580.2mn (after income tax), a 32.9% increase over the corresponding 2000 half-year result of A$436.5mn.*

In Brief

UK

The International Petroleum Exchange (IPE) has announced plans to invest over $10mn during the next year in a new futures trading platform which will be developed by the International Commodities Exchange (ICE) following the merger of the two operations. Trading of IPE Brent and IPE Gas Oil will be traded exclusively on the new electronic trading platform, which is expected to take between 12 and 18 months to develop.

Anglo Petroleum is reported to have bought Save, the UK's largest independent fuel retailer that went into receivership earlier this year, for £50mn.

The International Petroleum Exchange (IPE) has traded its first electricity futures contract. IPE hopes that the contract will become a benchmark for a power index in the near future.

Enron's Teeside 1,875 MW combined-cycle gas power station was temporarily closed after an explosion on 8 August that left three people dead. An investigation by the UK Health & Safety Executive is underway.

Centrica, which owns the Automobile Association, is to acquire Halfords' 129-strong network of garages, claimed to be the largest independent chain of car repair, service and maintenance centres in the UK. The purchase, from The Boots Company for £5.75mn in cash, is Centrica's first major acquisition investment on behalf of the AA.

Operations management specialist PGS Production Services has been awarded a six-month maintenance strategy review contract by BG Storage to review and implement changes to its maintenance systems at the company's onshore gas processing terminal at Easington.

Europe

Rotch Energy of the UK is reported to be acquiring a 75% stake in the Gdansk refinery, Poland, for an undisclosed sum – beating a rival bid by Hungarian oil and gas company Mol. Rotch is reported to have pledged $700mn investment in the refinery to upgrade and boost its capacity from 4.5mn t/y to 7mn t/y, as well as expand the refiner's Polish retail network from 269 outlets to 600.

EC and EU news update

There have been a number of energy related announcements from the EC and EU in recent weeks. *Keith Nuthall* reports.

- The European Commission has launched a series of legal proceedings against EU Member States which it claims have broken oil-related directives. It has decided to take Italy to the European Court of Justice (ECJ) over its special tax on engine lubrication oils, which Brussels claims contravenes EU excise duty laws.
- The Commission has also threatened Germany and Italy with legal action at the ECJ for failing to implement EU laws imposing maximum levels on the sulfur content of heavy fuel oil and gas oil. In addition, it has sent legal final warning notes to Britain, Austria, Greece and Italy for failing to write amendments to the Fuel Standards Directive, revising the measuring methods for the quality of petrol and diesel into their national legislation.
- The Commission has launched a formal state aid inquiry into money paid by Italy to farmers in Sardinia compensating them for the higher price of gas oil over that of natural gas, which is not readily available on the island.
- The European Investment Bank is providing a euro 47mn loan to Companhia de Gás de São Paulo (Comgás), owned by BG and Shell, to expand and modernise a natural gas distribution network in the State of São Paulo Brazil.
- A major EU research study has concluded that the 'true' price of using oil to generate electricity is double that usually assumed, taking into account the costs of dealing with the resulting pollution and health problems. The 'real' cost of using gas was 30% higher, said the resulting report.

Fixed fuel price deal cuts haulier costs

Bournemouth Transport has signed a one-year contract with Shell for delivery of 4mn litres of diesel at a fixed price. According to Bournemouth Transport's Chief Accountant, Claire Partridge, a similar contract with Shell in 2000 saved the company 'about £120,000 against spot prices' and 'cushioned' it when 'the fuel crisis was sending the spot prices soaring between August and September last year.'

Sibneft boosts Russian lubricants production

Sibneft has launched a new automated dispensing line for motor lubricants at its Omsk refinery, more than tripling production capacity to 2,500 t/month. Once the line is operating at full capacity, Sibneft will become Russia's second largest producer of motor lubricants. The company is also to begin sales of lubricants under its new Sibi Motor brand name later this year.

The company plans further investments in its lubricants business in order to soon launch what it claims will be Russia's first fully synthetic lubricants meeting the API's SL standard. It also plans to boost monthly production of all lubricants by one-third to over 20,000 tonnes by early 2002.

Esso boycott to run and run

On the eve of the Bonn climate change talks, *Brian Warshaw* spoke to Cindy Baxter and Lorne Stockman, Joint Coordinators of the 'Stop Esso Campaign' which is asking motorists to buy their fuel from service stations other than Esso. Asked how long the Campaign was planned to run, Baxter said: 'It will be a very long-term campaign that is only just beginning... and the boycott [of Esso products] will only end when Exxon changes its position on Kyoto.'

Sponsored by Greenpeace, Friends of the Earth, and People and Plants (a student organisation), the Campaign was launched on 8 May with the assistance of Bianca Jagger and other celebrities. The latest names to sign up are the singers Sting and Robbie Williams, and the environmentalist Jonathan Porritt, CBE, Chair of the Government's Sustainable Development Commission.

ExxonMobil had been chosen as the target, rather than some other oil company, because of the large financial donation it had made to the Republican Party, and the influence it was exerting on President Bush. Stockman said: 'ExxonMobil are working the hardest to undermine Kyoto and are still advocating that Kyoto is not the way to go. They have undermined the process whereas other [oil] companies have come out in favour of Kyoto'. He added that ExxonMobil, unlike companies such as BP and Shell, was making no investment in developing renewable energy sources.

Baxter said that it was not possible to make a realistic assessment of the effect the Campaign was having on Esso's sales, but she thought that the reaction of the company in embarking on market research to gauge and influence the public's perception towards them was a positive sign of concern. Esso also had sent out information packs to financial institutions seeking to reassure the capital market. In addition, the Campaign has been spreading – Germany, Norway and New Zealand joined in the boycott at an early stage, and similar action recently started in Malaysia and Finland, with Ireland being the latest recruit. She was very encouraged that in the first eight weeks of the Campaign, its website had received over half a million hits, and they were sending out 600 to 700 campaign packs each week to new enquirers. More countries are expected to join the boycott with the conclusion of the Bonn talks on world climate change.

Questioned about ExxonMobil's claim that the public would revolt against the Kyoto Protocol's requirement for mandatory carbon dioxide reductions when they realised the economic consequences on their jobs and on prices, Baxter suggested that the opportunities for jobs was extraordinary, with the development of renewable energy technologies and the transfer of technology to developing countries helping economies all over the world.

Economies could prosper without destroying the environment – she claimed that proof of this came from the Lawrence Berkeley National Laboratory in California which had just published the results of research done on China and showed that gross national product (GNP) had increased by 36% since the mid-1990s, while carbon dioxide emissions had gone down by 17%.

Counter to the economic consequences claim, she suggested, was 'that when the effects of global warming start to kick in they [people] will not be worried about their jobs, they'll be worried about whether they can get storm insurance on their house, whether their house is too close to the coast, the floods... malaria moving forward, heat waves and people dying, the effect that global warming will have on their lives.'

Challenged to refute the claim that it wasn't ExxonMobil or even President Bush that was the block to a US policy on reducing carbon dioxide emissions, but in reality it was the Senate, Baxter responded that in 1997 when it had voted a bipartisan 95 to zero against the Kyoto proposals, the effects of global warming hadn't been seen. Now, she continued, there was a different feeling in the Senate and in the country, and people wanted action on climate change. A recent *New York Times*/CBS News poll had shown people were prepared to pay higher prices to protect the environment, and that only 21% supported increasing the production of petroleum, coal and natural gas as a priority, against 68% who favoured conservation.

Since the interview took place, delegates from 178 countries to the world climate change conference have reached an agreement that it is hoped will enable sufficient governments to ratify and, in 2002, bring into legal force the Kyoto Treaty without the necessary participation of the US. The agreement requires the UK to reduce its greenhouse gas emissions by 12% from 1990 levels by 2010.

In Brief

***Vopak Mineral Oil Barging and Van** der Sluijs Tankrederij are planning to combine their brokering operations to create what they claim will be the 'largest brokering company for inland tanker shipping of petroleum products in the Netherlands, Belgium and the German Rhine area.' They are seeking approval from the European Commission and hope to have the joint venture operational by 1 January 2002.*

North America

***Ballard Power Systems, Shell Hydrogen** and Westcoast Energy have established a new Vancouver-based private capital joint venture – Chrysalix Energy – that will focus on promoting early stage companies with high growth potential in fuel cells and related systems, hydrogen infrastructure, maintenance and support techniques.*

Middle East

***Al-Kharafi Group of Kuwait is among** a diverse set of Arab bidders seeking to acquire a 20% interest in the 38% equity held by the National Bank of Egypt in the Cairo-based Middle Eastern Oil refinery. Merhav of Israel sold 22% of its 24% stake in the refinery to the Bank in May; the Egyptian General Petroleum Company holds the remaining interest.*

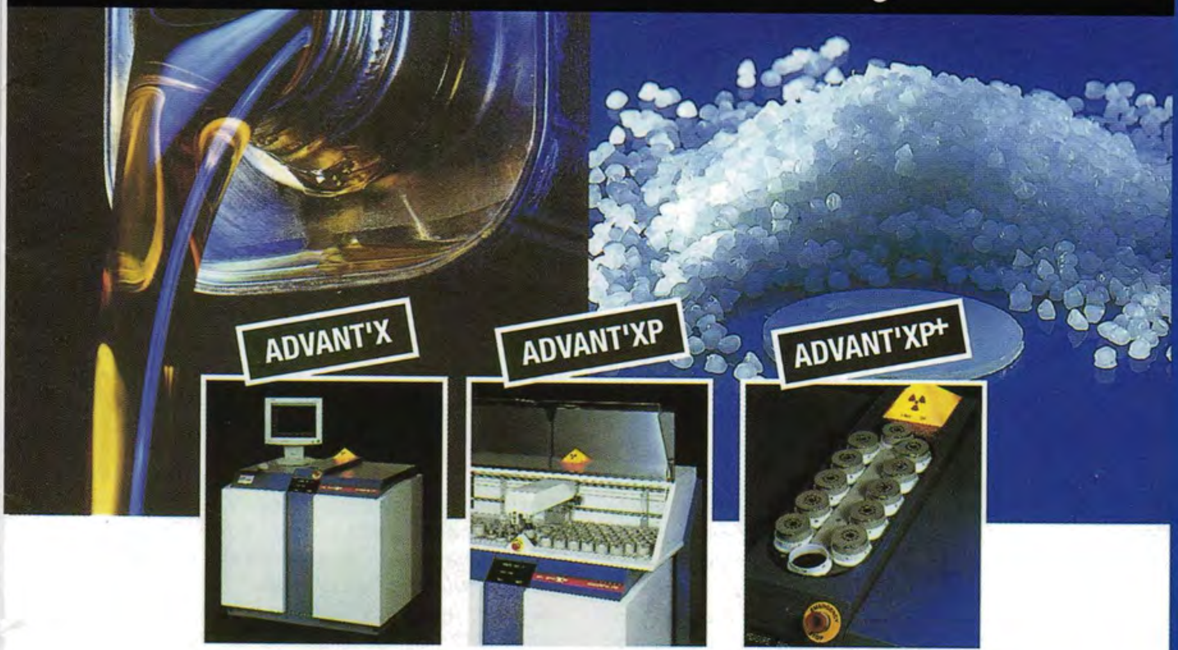
Russia & Central Asia

***Sibneft, along with some other com**panies, has acquired a 78.4% stake in Tyumennefteprodukt – a petroleum products distributor in the Tyumen region of Russia – from TNK, reports UFG. Tyumennefteprodukt operates 80 service stations; the deal brings to 996 the number of outlets that Sibneft now operates.*

***The Russian Government has decided** to sell an 85% stake in Norsi, a holding company for a 300,000 b/d refinery and two Volga region marketing companies, reports UFG. The stake is to be sold in two blocks of 40% and 45% for a total consideration of $22mn.*

***OMV of Austria is reported to be** planning to expand its retail network in Serbia and throughout the rest of eastern Europe to reach at least a 10% market share over the next three years.*

The Family



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NEWS Downstream

Simon wins Methanex outsourcing contract

Methanex, the largest producer and marketer of methanol in the world, has entered – through its new UK marketing office – into a new long-term contract with Simon Storage at its Riverside terminal on Teesside in northeast England.

Under the terms of the contract, Simon will provide new road loading facilities, weighbridges and operational systems. Methanol will be imported into the terminal by ship into existing storage or via pipeline from Vopak Terminal Teesside at the mouth of the River Tees.

Methanex (UK) was formed when Methanex purchased ICI's UK methanol business with effect from 1 January 2001.

In Brief

Latin America

***Chilean power generation company** AESGener is reported to have sold a majority stake in its Argentine subsidiary – Central Puerto – to TotalFinaElf for $225mn.*

***Anadarko Petroleum is reported to** have sold its Guatemalan production, pipeline, refinery and storage operations – operated by subsidiary Basic Resources International – to Perenco of France for $120.5mn.*

Africa

***ABB has been awarded a $93mn con**tract by Sonatrach to design and build the SC3 compressor station on the GPDF–Pedro Duran Farrell pipeline, one of two gas pipelines linking Algeria to Europe. Upon project completion, the gas pipeline – which crosses the Gibralter Straits – will increase its flow rate from 8bn to 11bn cmly.*

***Sasol of South Africa, together with** Mozambique's state company Petromoc, is understood to have established a 49%:51% fuels marketing joint venture in Mozambique.*

***The Energy Ministry of Ghana** is to make public the formula that is has been using since 1997 for calculating automatic adjustments in fuel pricing at the pumps to take into account taxes, levvies, changes in forex rates and distribution margins, reports* Stella Zenkovich, *in a bid to eliminate speculation on the fuel pricing structure in the country.*

***The Lithuanian Parliament has voted** to sell a 26.85% stake in the Mazhekai refinery to Yukos for $75mn and a guarantee of crude supply to the refinery, reports UFG. Shareholders of the refinery, including Williams of the US – have yet to approve the sale.*

***Gazprom CEO Alexei Miller has** stated that the company has no plans to conclude more gas contracts for supplies to the European market, although exports will remain an important part of the company's business, reports UFG. Exports are expected to total between 175bn and 205bn cmly over the next few years, compared with current exports of 180bn cmly. 'The acknowledgement that more gas contracts will not be signed immediately reflects the increasing pace of liberalisation of the European gas market and the consequent unwillingness on the part of large European gas purchasers to enter into long-term contracts at this stage of the market's development,' comments the analyst.*

Asia-Pacific

***India's Foreign Investment Promotion** Board is reported to have approved Gaz de France's (GdF) proposal to acquire a 50% interest in Petronet LNG – a joint venture between state-run companies Gas Authority of India, Indian Oil Corporation, Oil and Natural Gas Corporation and Bharat Petroleum. GdF bought a 10% stake in Petronet for $25mn earlier this year in order to participate in a project to import LNG to India from Qatar.*

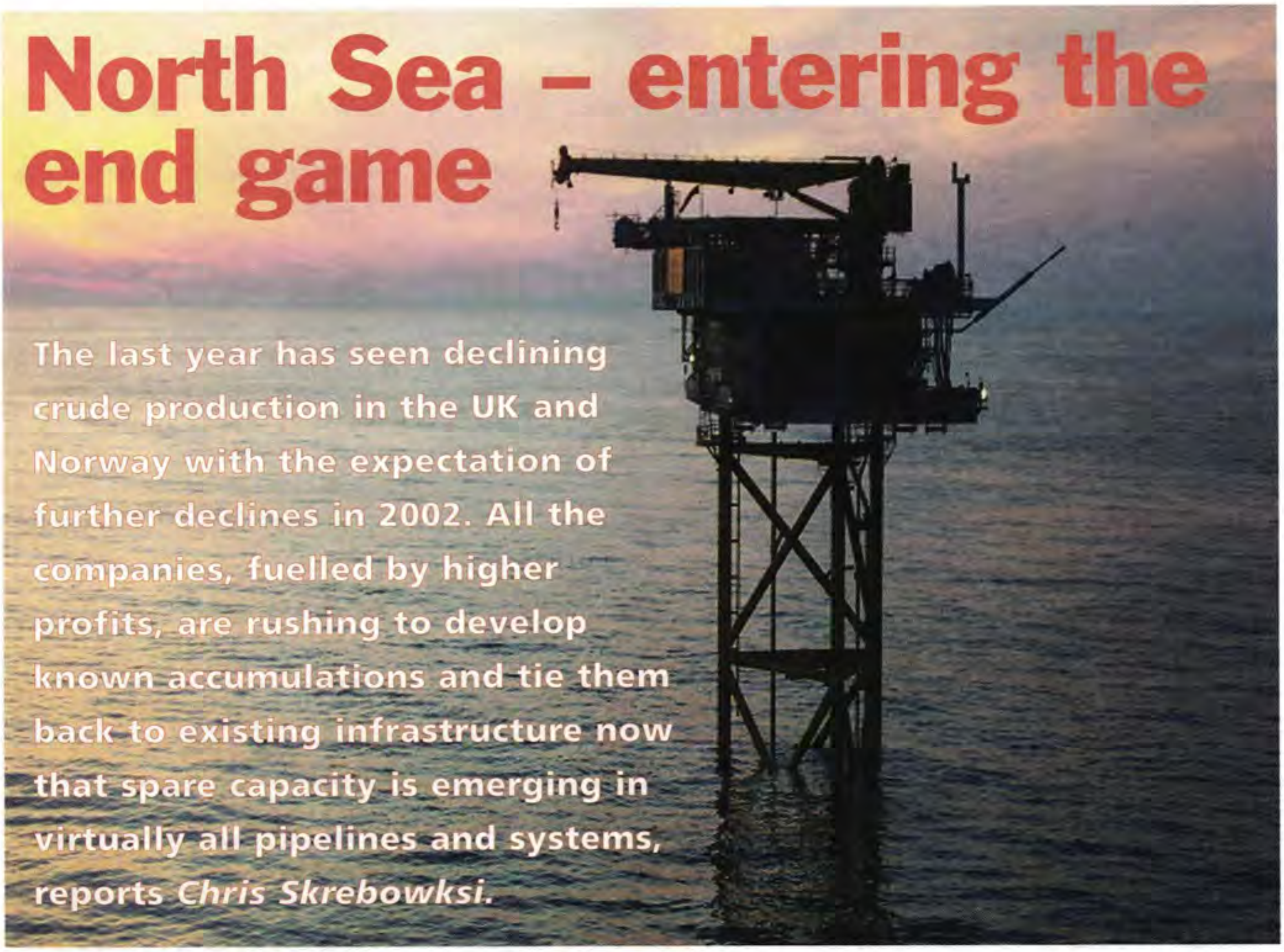
UK Deliveries into Consumption (tonnes)

Products	†Jun 2000	Jun 2001	†Jan–Jun 2000	Jan–Jun 2001	% Change
Naphtha/LDF	142,439	71,312	1,159,785	821,852	–29
ATF – Kerosene	925,077	1,014,033	4,758,302	5,255,789	10
Petrol	1,719,568	1,631,115	10,408,800	10,306,429	–1
of which unleaded	1,589,657	1,541,178	9,544,792	9,263,196	–3
of which Super unleaded	30,342	35,275	200,725	212,929	6
of which Premium unleaded	1,589,315	709,213	9,344,067	4,999,084	–46
ULSP (ultra low sulfur petrol)	–	796,690	–	4,490,758	–
Lead Replacement Petrol (LRP)	129,911	89,937	864,008	533,773	–38
Burning Oil	188,944	194,276	2,012,556	2,247,063	12
Automotive Diesel	1,291,834	1,325,671	7,655,900	7,112,549	–7.1
Gas/Diesel Oil	517,049	466,039	3,528,049	3,204,337	–9
Fuel Oil	100,303	98,927	816,478	1,068,769	31
Lubricating Oil	70,271	71,558	402,484	423,250	5
Other Products	656,867	649,199	4,146,919	4,131,987	0
Total above	5,612,352	5,522,130	34,889,273	35,431,657	2
Refinery Consumption	431,621	294,389	2,638,492	2,122,426	–20
Total all products	6,043,973	5,816,519	37,527,765	37,554,083	0

† Revised with adjustments

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

North Sea – entering the end game



The last year has seen declining crude production in the UK and Norway with the expectation of further declines in 2002. All the companies, fuelled by higher profits, are rushing to develop known accumulations and tie them back to existing infrastructure now that spare capacity is emerging in virtually all pipelines and systems, reports *Chris Skrebowksi*.

The buzzard is not normally associated with good news as it is a carrion feeder like the vulture. However, for the North Sea, last month's discovery of the Buzzard field has been the best news for many years. The Buzzard find in block 20/6 tested 6,547 b/d of oil and 0.97mn cf/d of gas. The operator, PanCanadian, has already announced that reserves could be between 200mn and 300mn barrels, which would almost certainly make it the largest UK find since Schiehallion in October 1993. It is a find of sufficient size that a traditional steel platform will possibly be required.

So far, this year has proved quite successful in terms of exploration in the UK sector. In addition to Buzzard, Talisman has had an oil find called Lucy in block 15 and BP has had the Claw discovery close to its West of Shetland production facilities. Conoco had a gas find with the K field in block 44 and Amerada Hess has made a gas discovery in block 47 called York. Also in block 47 BG has a gas condensate field called Rose.

The contrast with last year could not be more stark. In 2000, according to Wood Mackenzie (the Edinburgh-based consultants) there was only one significant UK sector discovery – Amerada Hess' Rochelle oil find in block 15/27. The UK Government's *Brown Book* is slightly more positive than Wood Mackenzie noting six significant discoveries in 2000.

The recent upturn in discovery, although a huge bonus, is misleading. IHS Energy reports that over the last five years the UK has replaced just 17% of the 1bn b/y production it averaged over the period – roughly a find rate of 170mn b/y. Norway is similarly failing to replace production, with discovery averaging 37% of production over the last five years. This equates to roughly 450mn b/y. There have, however, been some notable recent Norwegian discoveries (see p19) – the Bella Donna gas field by ExxonMobil in 2000, Agip's 2000 Goliath gas find and Statoil's discovery of light oil in the M structure this year.

In 2000, production from new fields brought onstream in the course of the year in the UK sector was averaging little more than 90,000 b/d by year end. The delays to Elgin/Franklin and the forced shutdown of Shearwater meant that a considerable volume of new production anticipated in the year failed to materialise. As a result, year-on-year UK sector production is currently running 10% below year earlier levels. Underlying decline rates for the fully developed fields are now running at over 15%/y, which means that around 250,000 b/d of new or incremental production is needed each year just to maintain production levels in the UK sector alone.

The International Energy Agency in its July 2001 *Oil Market Report* has issued its first estimates of 2002 production. It expects the UK sector to produce marginally less than in 2001 and it expects this year's production to be 100,000 b/d below 2000 levels. For Norway, it anticipates that 2001 will be marginally above 2000 levels, but that 2002 will be 60,000 b/d lower. For what it calls 'other North Sea' – predominantly Denmark, with a small contribution from the Netherlands – production in 2001 is expected to be 50,000 b/d below 2000 levels, but then to recover by 40,000 in 2002.

Table 1 lists the known field developments, probable and possible discoveries. It is notable that throughout the North Sea any major new discoveries are being developed very rapidly. These, however, form quite a small part of the development portfolio, the rest being accumulations discovered up to 25 years ago. A combination of improved technology, allowing much longer tie-backs than previously practi-

continued on p17 . . .

North Sea overview

Field name	Oil/gas	Block no.	Operator	Start-up	Oil reserves	Gas reserves	Prod. system	Peak prod. (yr)
UK								
Onstream 2001								
Angus (redvlpmt)	oil	31/21, 31/26a	Amerada Hess	3Q-01	15mn b		to Fife-Fergus FPSO	
Beauly	oil	16/21c	Talisman	**Mar-01**	3mn b		horiz well to Balmoral FPS	10 kb/d
Blake	oil	13/24a, 24b, 29b	Talisman	**Jun-01**	65mn b		8 subsea to Ross FPSO	40 kb/d (02)
Brigantine A,B & C	gas	49/19, 49/18	Shell	**Jan-01**		280bn cf	2NNM plat via Corvette	130mn cf/d (02)
Chestnut Ph1 EWT	oil	22/2a	Amerada Hess	1Q-01	20mn b		subsea horizontal well	
Davy North	gas	49/30a	BP?	2001			1 well subsea tieback	
South Everest	gas/cond	2/9, 22/10a, 23/21	BP	3Q-01			tieback to Lomond	
South Dunbar	oil	3/14a	TotalFinaElf	end 2001			tieback to Dunbar plat	
Elgin/Franklin	cond	22/30b, 30c, 29/5b	TotalFinaElf	**Jun**/Aug 01	244/123mn b cond	889/821bn cf	PDQ + wellh'd plat	140 kb/d 13mn cm
Foinaven East	oil	204/24a, 204/25b	BP	4Q-01	38mn b		tieback to Foinaven FPSO	18 kb/d (02)
Hamilton East	gas	110/13a	BHP	Oct-01		75bn cf	1 well tieback to Douglas plat	
Hannay	oil	20/5c	Talisman	4Q-01	8mn b		2 well tieback to Buchan ss	7 kb/d (02)
Halley	oil/gas	30/12b	Talisman	Jun-01	9mn b	13bn cf	2 ER wells from Fulmar	14 kb/d (02) 25mn cf/d (02)
Jade	gas/cond	30/2c	Phillips	Oct-01	30mn b (cond)	400bn cf	steel plat via Judy/CATs	15 kb/d (02), 200mn cf/d (02)
Kestrel (SA)	oil/gas	211/21a	Shell	3Q-01			2 well tieback to Tern	
Kyle	oil	29/2c	Can Nat Res's	**Apr-01**	35mn b	90bn cf	4ss wells via Curlew FPSO	22 kb/d(02), 60mn cf/d (03)
Magnus NW	oil	211/7a	BP	Dec-01	10mn b		ERD from Magnus	7 kb/d
Nuggets N1,N2,N3	gas	3/18c, 19a, 19b, 20a, 24a	TotalFinaElf	4Q-01		300bn cf	5 subsea wells to Alwyn North	165mn cf/d
Shearwater	cond	22/30b	Shell	**Apr-01**	140mn b liquids	710bn cf	PDQ + wellh'd plat	68 kb/d (02), 350mn cf/d (02)
Onstream 2002								
Alba extreme sth	oil	16/26	Chevron	2002			7 subsea wells to Alba plat	
Blane	oil	30/3a	Enterprise	1Q02	15-40mn b		Ph1 FPSO, Ph2 subsea	15-25 kb/d, 6-10mn cf/d (Ph1)
Braemar	oil/gas	16/3c	Marathon	2001	15mn b	120bn cf	1 subsea well to Brae B	5 kb/d (02), 40 mn cf/d (02)
Caledonia	oil	16/26	Chevron	2002	10.5mn b		subsea to Brittannia	13 kb/d
CMS III	gas	44/22a	Conoco	4Q-02		415bn cf	Tiebacks to Murdock plat	205mn cf/d (03)
Goosander	oil	21/12, 21/13a	Shell	mid-02	16mn b++		subsea to Kittiwake	15 kb/d
Hoton	gas	48/7b	BP	1Q-02		95bn cf	wellh'd plat to W.Sole	40mn cf/d (03)
Leadon area	oil/gas	9/14a, 9/14b	Kerr-McGee	1Q-02	145mn b		16 subsea wells to FPSO	50 kb/d (03)
Magnus EOR	oil	211/12a	BP	2002	additional 60mn b	200bn cf	infill wells, misc gas injection	
Juno project (ECA2)	gas	47/3b, 3c, 4a, 4b	BG	4Q-02		400bn cf	subsea + Minerva plat	300mn cf/d (03)
Nuggets N4	gas	3/18c, 19a, 19b, 20a, 24a	TotalFinaElf	2002		500bn cf	subsea	150mn cf/d (04)
Otter (Wendy)	oil	210/15a	TotalFinaElf	4Q-02	35mn b		5 subsea wells to Eider plat	30 kb/d (03)
Penguin A,B,C,D	hvy oil	211/13	Shell	2002/3	30mn b	33bn cf	subsea to Brent	45 kb/d (03), 110mn cf/d (02)
Skene (ex Sorby)	gas/cond	9/19	ExxonMobil	1Q-02	29mn b	380bn cf	7 subsea wells to Beryl A	27 kb/d (04), 180mn cf/d (04)
Skua	oil/gas	22/24b	Shell	Jun-02	25mn b	24bn cf	2 subsea wells to Marnock	19 kb/d (02), 15mn cf/d (03)
Wood (SA)	oil/gas	22/18	Nisus	2H02	15mn boe		1-2 subsea to Arbroath	
Onstream 2003								
Goldeneye	gas/cond	14/29a, 20/4b	Shell	2003	15mn b	500bn cf	platform	5 kb/d (03), 200mn cf/d (03)
Harding area gas	gas	9/23b	BP	end-03	appraisal		tiebacks to Harding plat	
Kessog (SA)	gas/cond	30/01c	BP	2003	100mn boe		unmanned plat or subsea	
Skene Ph2 (Brora)	gas/cond	9/19	ExxonMobil					
Onstream 2004								
Clair South	oil	206/7a, 8, 9a, 12, 13a	BP	2004	263mn b		1 or 2 fixed steel platforms	80 kb/d (05)
Glenelg	oil/gas	29/4d	TotalFinaElf	2004	100mn boe		wellhead plat via Elgin PUQ	
Probable develops								
Alder	oil/gas	15/29a	Chevron	2004	22.4mn b (liquids)	187.5bn cf	subsea tieback	
Amy and Argo	gas	48/10b,48/9a	Conoco					
Bedevere	gas	48/14	ExxonMobil	2003		100bn cf	ERD	40mn cf/d (04)
Bennachie	oil	21/15a, 15b	Enterprise	2003	15mn b		subsea to Forties or Nelson	10 kb/d (01)
Beta (UK)	gas	44/24a	Consort Resources	2002		75bn cf	wellh'd plat to Orca	35mn cf/d (03)
Cavendish	gas	43/19a	Highland Energy	2003	100bn cf		subsea to Trent	51mn cf/d (04)
Devenick	oil	9/24b	BP	2004	40mn b (cond)	480bn cf	tieback to Harding	
Dolphin		22/18	BP					
Heather West	oil	2/5	DNO Heather	2002			subsea tieback	
Jacqui	oil/gas	30/13	Phillips	2002	14mn b	90bn cf	subsea to Judy	10 kb/d (02), 50mn cf/d (05)
Josephine	oil/gas	30/13	Phillips	2003	13mn b	95bn cf	subsea to Judy	8 kb/d (03), 50mn cf/d (03)
Kate/Tornado	oil/gas	22/23b, 28a	BP?	2002/3	30mn b	20bn cf	subsea	20 kb/d (02), 15mn cf/d (01)
Lewis	oil	quadrant 9	ExxonMobil	2003/4			tieback to Beryl Alpha	
Maclure	oil/gas	9/19 Area N	BP	2002	20mn b	30bn cf	subsea to Harding	15 kb/d (02), 20mn cf/d (06)
Mandarin	oil	22/23b, 22/28d, 22/28a	Shell					
Mariner	hvy oil	9/11a	Texaco	2002?	100mn b		project on hold	
Orca and Minkie	gas	44/24a, 29b, 30	CalEnergy	2002		150bn cf	wellh'd plat to D/15-FA	72mn cf/d (03)
Perth/Lowlander	oil	15/21b	Amerada Hess	2002	45mn b		subsea to Scott	20 kb/d (03)
Pilot	oil	21/27	TotalFinaElf	2002?	77mn b		floater?	

Table 1: North Sea fields onstream in 2001 and beyond

Field name	Oil/gas	Block no.	Operator	Start-up	Oil reserves	Gas reserves	Prod. system	Peak prod. (yr)
Pine	oil	16/12	Lasmo					
Puffin	oil/gas	29/4a, 5a, 9a, 10	Shell	2004	40mn b	320bn cf	wellh'd plat to Shearwater	18 kb/d (2008), 150mn cf/d (2008)
Rhum	oil	3/29a	BP				subsea to Bruce or Harding	
Rivers			Burlington	2002			subsea	
Solan/Str'thm're (SA)	oil/gas	204/30	Amerada Hess				FPSO	40 kb/d
Suilven	oil	204/19	BP	2003?				
York	gas	47/3a	Amerada Hess	2003?	test 24.7mn cf/d	200bn cf		
Possible dev's								
Ani			Shell				subsea tieback	
Alwyn North Trias			Total					
Appleton area	gas/cond	30/11	Talisman		40mn b	60bn cf		
Arbroath/Montrose	oil	22/17, 18	BP				poss comp platform	
Atlantic(Brora)	gas/cond	14/26	BP				tieback to Goldeneye?	
Auk North	oil	30/16	Shell		25-30mn b		subsea to Auk	
Babbage	gas	48/2a	TXU	2002?		165bn cf	subsea to Johnston	
Beechnut	oil/gas		Amerada Hess	2002/3			FPSO	20 kb/d
Block 15/23	cond	15/23d	BG					
Block 16/26	oil	16/26a	BP	2002			platform	
Blythe	gas		BP					
Bressay	hvy oil	3/28a	Chevron	2003	200mn b			
Brigitte	gas		BG					
Cavendish	gas	43/19a	Highland Energy	2003		100bn cf	subsea to Trent	52mn cf/d (2001)
Cromarty	gas/cond	13/30b	Amerada Hess				tieback to Goldeneye?	
Elm	oil	16/12a	Lasmo		6mn b		ERD from Tiffany	5 kb/d (2001)
Enoch West	oil/gas	16/13a	Enterprise	2002	12mn b	16bn cf	subsea to Miller or Brae	10 kb/d (2003), 15mn cf/d (2003)
Ensign	gas	48/14	Centrica	2002			platform	
Ettrick	oil	20/2a	Enterprise	2002	35mn b		FPS?	
Flyndre			TotalFinaElf	2002			subsea tieback	
Fyne/Dandy	oil	21/28a	Lasmo	2002?	39mn b		FPSO?	
Gadwall	oil/gas	21/19	Shell	2002	9mn b	7bn cf	subsea to Kittiwake	10 kb/d (2002), 7mn cf/d (2002)
Glenn			BP	2002			subsea tieback	
Hunter	gas	44/23a	TotalFinaElf	2002			subsea tieback	
Inde NE	gas	49/19	Shell			45bn cf	subsea tieback	50mn cf/d (2002)
Johnston/Gamma	gas	43/27a, 43/26a	Consort Energy	2002			ERW	
Lennox West			Burlington	2002			subsea	
Melville			Amerada Hess	2003			subsea	
Mirren	oil/gas	22/25b	Shell	2004			subsea	
Nevis Central			ExxonMobil	2002			subsea	
Nevis Far North			ExxonMobil	2002			ERW	
Peik UK	oil/gas	9/15a	TotalFinaElf	2002	20mn b	350bn cf	subsea to Beryl A	9 kb/d (2003), 110mn cf/d (2003)
Ramsay	gas	53/5b	BP	2002?		75bn cf	ERW from Davy?	
R Block	oil	15/27	Phillips					
Scoter	gas/cond	22/30a	Shell	2003			subsea	
Seymour			BG	2002			ERW	
Skye	oil	211/23a, 23c	Shell	2001	20mn b		subsea to Dunlin	11 kb/d (2002)
Thebe	gas	49/22	Conoco	2001		74bn cf	with ECA Phase II	35mn cf/d (2002)
Tornedo	oil	22/23b, 28a, 28c	Shell	2002	30mn b			20 kb/d (2003)
Wissey	gas	53/04	BP	2002			subsea	
Other named possibles: Anglia, Anglia NW, Conival, Blane, Don NE, SW,S Don West, Fiddich, Howe, JI, Jill and Julia, Marcel/Bravo, Millburn, Selkirk, West Wicks								
Key discoveries								
Clapham	oil	21/24	Veba Oil		5,894 kb/d on test		subsea to Guillemot NW	
Rochelle	oil/gas	15/27-9	TotalFinaElf?		7,973 kb/d on test	4.67mn cf/d on test		
Lucy	oil	15/12b, 15/17	Talisman		20-50mn b	10bn cf	tieback to Piper	
Claw	oil		BP				tieback to Schiehallion	
K field	gas	44/22a, 44/23a	Conoco	4Q2002		80bn cf	Caister Murdock (CMS III)	
York	gas	47/3a	Amerada Hess	2003?			incorp in ECA2?	
Buzzard	oil	20/6	PanCanadian		200-300mn b		platform?	
Rose-R2	gas/cond	47/15b	BG			test 30mn cf/d, 90 b/d (cond)		
Netherlands 2001 and after								
G17-4	gas	G17	TransCanada Intl	2002	12bn cm			
Hanze	oil	F/2A	Veba Oil	Aug-01	35mn b	58bn cf	steel grav platform, via A6/	38mn cf/d (01)
K/1A	gas	J/3A, K/1A	Elf Petroland	2002		414bn cf	platform	83mn cf/d (2003)
K12-13	gas	K12, K13	TransCanada Intl		4-10bn cm			
L1A-A	gas	L1A-A	Elf Petroland		5bn cm		sat platform L4PN	
L/13-FA	gas	L/13	NAM	2002		30bn cf	platform	
L/8-P4	gas	L/5C, L/8C	Wintershall	**Jan-01**		125bn cf	platform	
P6-d	gas	P6	Clyde	Oct-01		14bn cm	platform	
Possible dev's								
A&B Quad	gas	A/12A	NAM	2004			platform	
Beta	gas	D/15	NAM	2001		38bn cf	subsea	18mn cf/d (2002)
G/16A	gas	G/16A	NAM	2002		226bn cf	platform	55mn cf/d (2003)
K/15-FE	gas	K/15	NAM	2002		30bn cf	platform	
K/2B	gas	K/2B	NAM	2001		86bn cf	platform	17mn cf/d (2002)
K/2B-K/3A	gas	K/2B,K/3A	NAM	2001		260bn cf	platform	

Table 1: North Sea fields onstream in 2001 and beyond

continued overleaf...

Field name	Oil/gas	Block no.	Operator	Start-up	Oil reserves	Gas reserves	Prod. system	Peak prod. (yr)
K/3A	gas	K/3A	NAM	2001		174bn cf	platform	35mn cf/d (2002)
K/4-BE	gas	K/4A	TotalFinaElf	2001		150bn cf	platform	
L/7-G	gas	L/7	Elf	2001		30bn cf	platform	
K/7-FB	gas	K/7	NAM	2001		150bn cf	platform	
K/7-FE	gas	K/7	NAM	2001		100bn cf	platform	
K/8-FB	gas	K/8	NAM	2002		40bn cf	platform	
L/8-14	gas	L/8B	Wintershall	2001		50bn cf	subsea	
M/7-5	gas	M/7	Clyde	2002/3		91bn cf	platform	45mn cf/d (2001)
Orca	gas	D/15, D/18A	NAM	2001		75bn cf	platform	40mn cf/d (2002)
Q/4-8	gas	Q/4	Clyde	2001		69bn cf	platform	34mn cf/d (2000)
Key discoveries								
K15	gas	K/15	Shell, ExxonMobil			11bn cf		
Norway Onstream 2001								
*Garn West	oil/gas	6407/9	Shell	Nov-01	32.7mn b		2 subsea to Draugen	
*Glitne/Dagny	oil	15/5, 15/6	Statoil	Aug-01	25mn b		Petrojarl FPSO	19 kb/d (2001) 2/3 year life
*Gullfaks South ph2	oil/gas	34/10, 33/12	Statoil	Oct-01	90mn b	58.5bn cm	via Gullfaks C	34 kb/d, 4.8bn cm, 0.5mn t NGLs
*Huldra	gas/cond	30/2, 30/3	Statoil	Aug-01	46.5mn b (cond)	19.1bn cm	NNM jack-up wellhead plat	3.2bn cm, 1.7mn cm (cond)
*Ringhorne	oil/gas	25/11,25/8	ExxonMobil	**May-01**	280mn b	8.2bn cm	w'hd + 5 subsea via Balder	
*Snorre II (B)	oil	34/4, 34/7	Norsk Hydro	**Jun-01**	365mn b	14.3bn cm	subsea to Snorre TLP	108 kb/d
*Tambar	oil	1/3, 2/1	BP	Jul-01	41mn b		2 subsea via Ula	
*Vale	gas/cnd	25/4	Norsk Hydro	2001/2	21mn b (cond)	2.5bn cm	1 subsea to Heimdal riser plat	
*Visund North	oil	34/8	Norsk Hydro	3Q2001	19mn b			
Onstream 2002+								
Barden	gas	6305/7	BP Amoco			100bn cm	design, 20km Ormen Lange	
Dagny	gas/cond	15/6 and 15/5	Statoil		1mn cm (cond), 1mn t NGL	5.8bn cm	subsea via Sleipner A or T	
Ebba	oil/gas	2/7-31	Phillips	2002		appraisal	appraisal	appraisal
Fangst	oil	6507/3	Statoil				floater	
*Fram West	oil/gas	35/11,31/2	Norsk Hydro	Oct-03	210mn b	18bn cm	subsea via Troll C	60 kb/d
Freja	oil	2/12 (Nor)	Amerada Hess	2002/3	2mn cm	0.3bn cm	NNM plat to Harald/Valhall	
Gjoa	oil/gas	35/9, 36/7	Norsk Hydro	mid-2006	7.6mn cm	19.9bn cm	Sogn area development	
Goliath	oil	Barents Sea	Agip	Jun-09			FPSO	
*Grane (Hermod)	oil	25/11	Norsk Hydro	Oct-03	704mn b (hvy oil)	1.8bn cm	PDQ platform	over 200 kb/d (2005-09)
Kappa	oil/gas	30/6, 9	Norsk Hydro	2001/2	1mn cm	2.7bn cm	ERW from Oseberg B	
Kristin	gas	6406/2-3, 11	Statoil	2005	40.4mn cm Cnd,8.5mn t NGL	35.4bn cm	semisub via Aasgard facilities FEED contract to Kvaerner	
*Kvitebjorn	oil/cond	34/11	Statoil	Oct-04	135mn b (cond)	52bn cm	steel platform (Aker to build)	6bn cm/yr
Lavrans	oil/gas	6406/2	Statoil	2006	4.4mn t NGLs, 7.6mn cm cnd	28.3bn cm	subsea to Kristin	
Mikkel	gas/cond	6407/6, 6407/5	Statoil	3Q2003	1mn cm, 4.6mn cm (cond)	20.4bn cm,6.3mn t ngl	4 subsea to Asgard B	
Nyk High	gas	6707/10	BP	2003+	40bn cm		FPSO	
Ormen Lange	gas	6305/4,5,7,8	Nor Hydro/Shell	2006	23.7mn cm cond	400bn cm	subsea to platform in 250m?	20-yr plateau
Oseberg Delta	gas/cond	30/9	Norsk Hydro	2002	15-20mn b	10-12bn cm	subsea via Oseberg	
*Rogn South	oil/gas	6407/9	Shell	2002	35mn b		2 subsea to Draugen	
Sigyn	gas/cond	16/7	ExxonMobil	2002	2.6mn t NGL,5.6mn cm (cnd)	5.6bn cm	tieback to Sleipner A	
Skarv	oil	6507/3,5,6	BP	2003+	20.9mn cm, 10.1mn cm (cnd)	69.1bn cm	FPSO	100 kb/d
Skirne + Byggve	gas/cond	25/5	TotalFinaElf	2002	0.9mn cm (cond) +0.7mn cm	4.2bn cm + 2.4bn cm	subsea to Heimdal	
Sleipner West upgrade		7120/5,6	Statoil	2004/5			alpha nord reservoir to Sleipner T	
Snoehvit+ others	oil/gas	7120/5,6,7,8,9, 7121/4,5,	Statoil	2005+	11.4mn cm, 19.7mn cm Cnd	167.2bn cm,5.8mn t NGL	subsea to shore	
Sogn	oil/gas		Norsk Hydro	2003/04	315mn b	63bn cm	FPO or subsea	
STUJ	oil	34/7	Saga	2002/3	14mn b		subsea	6 kb/d
Svale	oil	6608/10	Statoil	Jun-09	18.5mn cm		subsea via Norne	
Tjalve	oil/gas	2/4	Phillips	2002/3	1mn cm	1.6bn cm, 0.1mn t NGL	subsea via Tor	
Tommeliten A	oil/gas	2/4	Statoil	2001	3.2mn cm	3.5bn cm + 0.3mn t	subsea	
Trym	gas	3/7, 8	Shell	2001	0.8mn b (cond)	3.3bn cm	subsea to Harald (Denmark)	
*Tune A (ex Draken)	gas/cond	30/8,30/ 5, 30/6	Norsk Hydro	Oct-02	44mn b (cond)	27bn cm	subsea to Oseberg D	
Tyrihans N &S	gas/cond	6407/1	Statoil	2006	15.5mn cm cnd,4.6mn t NGL	24.5bn cm	subsea to Kristin/Asgard	
Vale	gas/cond	25/4	Norsk Hydro	2002	3.1mn cm cond	2.4bn cm	subsea to Heimdal	
Valhall flank	oil/gas	2/8, 2/11	BP Amoco	1Q-03	additional 183mn b		2 well plats	
Volve	oil/gas	15/9	Statoil	2003	4.6mn cm, 0.1mn t NGL	0.5bn cm	wellhead plat via Sleipner	
1/3/09	oil	1/3	BP Amoco		30mn b		w'hd or s'sea via Gyda or Ula	
35/8	gas/cond	35/8, 35/11	Norsk Hydro		3.7mn cm (cond) 3.1mn t NGL	20.8bn cm	linked to area development	
Denmark 2000 and after								
Adda	oil/gas	5504/8	Maersk	2001+	1mn cm	1bn cm	subsea to Tyra?	
Alma	gas	5505/17	Maersk	2003	6mn b	30bn cf	platform	4 kb/d (2004), 22mn cf/d (04)
Amalie	gas/cond	5604/26a	Danop	2000	13mn b	92bn cf	platform	7 kb/d (2002), 42mn cf/d (06)
Bertel	oil/gas							
Boje	oil/gas							
Elly	gas	5504/6a	Maersk	2002/3	0.8mn cm	3mn t NGLs	NNM platform	
Freja	oil/gas							
Gert	oil	5603/27a	Maersk	2000	9mn b	7bn cf	platform	6 kb/d (2001), 5mn cf/d (01)
Igor	oil/gas	5505/13	Maersk	2002	0.8mn cm	2bn cm	NNM platform to Dan?	
Lola	oil/gas							
Nini-1	oil	5605-10-01a			5,856 kb/d on test			
Sif	oil/gas							

*Sources: UK Government (*Brown Book 2001*), Norwegian Petroleum Directorate (2000 annual reports), Wood Mackenzie,* Petroleum Review
Dates in bold equals onstream; * Approved field developments in Norway

Table 1: North Sea fields onstream in 2001 and beyond

Ageing giants and brown fields

Although much emphasis has been placed on discovery and new field developments, most of the remaining reserves in the UKCS are, in fact, in the giant fields. Most of these are now elderly and well depleted (see **Table 2**). The table takes the operators' latest estimates of reserves as printed in this year's *Brown Book* (2001) and compares these with the 1997 and 1990 estimates. Remaining reserves are calculated and converted to million barrels using the Brown Book conversions and this is compared with production in 2000 in b/d.

The first and most notable observation is that reserves are still being actively revised even though most of the fields are old and presumably well understood. It is not clear the degree to which these revisions reflect improved recovery technology as opposed to a very literal interpretation of SEC rules on reserves disclosure. If it is the latter, then the increases represent the movement of reserves from 'probable' to 'proven.' Some of the changes can be associated with enhanced recovery projects – Magnus and Schiehallion – and change of operations – Brent.

These latest estimates of proven and produced reserves show that the 10 giants represent 47.8% of the UKCS' total proven and produced reserves. Surprisingly, given that most of the 10 fields are heavily depleted, their production – 466,251 b/d in 2000 – accounts for just under 20% of UKCS production.

As noted in the July 2001 editorial, discovered oil reserves in the UKCS were 72% depleted by end-2000. However, among the larger fields, mostly found early in the region's development, most are now over 90% depleted. The irony is that small increases in recovery from the early giants – so called brownfield developments – will probably yield more oil than most of the new field developments currently underway.

Field name	Start-up date	Reserves estimate at end-2000 (mn tonnes)	Percent depleted end-2000	Reserves % growth 1990–2000	Reserves % growth 1997–2000	Remaining reserves (mn barrels)	Production in 2000 (b/d)
Forties	1975	347.42	91.401	4.393	-0.032	227	56,541
Brent	1976	324.55	77.065	34.612	19.54	584	75,943
Ninian	1978	158.90	93.355	1.204	-0.694	79	35,157
Piper	1976	144.66	91.027	13.995	2.814	97	23,651
Magnus	1983	129.90	72.135	27.28	13.26	273	60,203
Beryl	1976	128.42	76.830	19.572	-37.172	226	33,677
Claymore	1977	86.80	78.061	23.471	9.458	137	30,911
Statfjord(UK)	1979	83.20	88.446	28.47	2.425	73	24,695
Schiehallion	1998	79.87	15.723	–	31.95	474	120,711
Fulmar	1982	79.64	89.279	4.789	0.176	65	4,762
Total		**1,563.36**				**2,235.00**	**466,251**
UKCS Total		**3,269.11**					**2,361,820**

Sources: Development of UK Oil & Gas Resources 2001 (Brown Book), Petroleum Review *calculations*

Table 2: The 10 giant fields of the UKCS with original reserves of over 66mn tonnes (500mn barrels) liquids

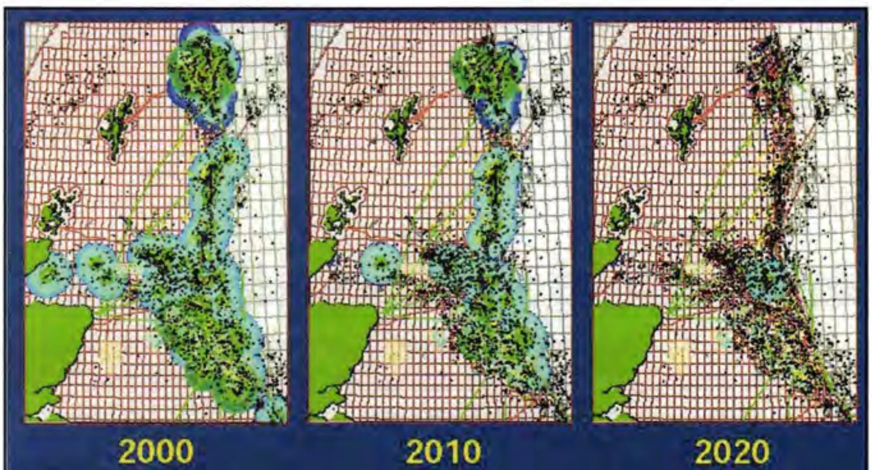


Figure 1: The window of opportunity is closing

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cable, and the recognition that once the key infrastructure is removed small accumulations could never be economically developed has produced a positive rush to develop. The UK Government now anticipates that UKCS investment in 2001 will reach £4bn, 25% up on the £3bn invested in 2000. Current expectations are that investment will decline to £3bn (2002), £2.5bn (2003), reaching £1bn in 2005. The number of exploration and appraisal wells drilled in the UKCS is expected to be 47 in 2001, two higher than 2000, and then fall to 39 in 2002 and 26 in 2003.

A map of existing and future infrastructure (see **Figure 1**) has been widely shown around conferences this year. The map clearly shows that virtually all the 315 discoveries in the UK sector to date are within 35 km of infrastructure and so could be produced. Latest technical developments suggest that a 70-km tieback may be perfectly possible. Over time the infrastructure will be removed so for many small UK accumulations it is 'now or never.' Similar considerations apply, although with rather less urgency, to the Norwegian and Danish sectors.

In an important sense, the discovery rate is now so low that projections of future discovery will have only limited impact on decline rates. If no new production was brought onstream the UK would cease being self-sufficient (1.6mn b/d) by 2Q2003. In fact, over 200,000 b/d of new capacity will come onstream in 2001, with a further 100,000 b/d in 2002, 50,000 b/d in 2003 and 100,000 b/d in 2004. This should delay the date at which the UK becomes a net importer until mid/late 2005. The UK Offshore Operators Association (UKOOA) is a little more optimistic, timing net oil imports for early 2006.

In contrast, Norway hopes to hold oil production near current production levels (3mn b/d) for the next five years before decline really sets in. Dutch offshore oil production is so low that one find could radically change the outlook, while Danish production looks set to decline gently.

The challenge of the next few years in the North Sea is to find ways to slow the decline and enhance the recovery of the larger fields while developing lower cost drilling and development schemes for the large number of marginally economic small accumulations.

North Sea sector round-up

Nick Terdre reports on recent developments in the North Sea, outside of the UKCS.

Denmark

Mærsk Olie og Gass is pushing ahead with the further development of the Halfdan field which, with an estimated 267mn barrels of oil, is Denmark's fourth largest oil field. Having brought the field onstream last year through a wellhead platform, and now being in the throes of drilling an additional 15 wells which comprise the second stage, Mærsk is now seeking approval for phase three. This involves the addition of process facilities to the wellhead platform, and the installation of an accommodation platform and flare platform at the field centre, plus a wellhead satellite platform some 2 km to the north-east. Contract awards are being prepared, and by 2005 peak production of 100,000 b/d should be reached.

Mærsk has also initiated the development of Tyra South-East, for which Heerema will both build the platform and install it, while DSND will install pipelines back to the Tyra field centre. Due onstream no later than October 2002, the field looks likely to achieve start-up in the early months of next year.

In July 2001 Statoil started drilling a long-reach producer from the Siri platform with jack-up *Noble George Sauvageau* to access the small Stine reservoir located 6–7 km to the east. This followed a short appraisal well in June which found oil.

Ireland

Enterprise is developing the Corrib gas field in the Slyne Trough, which will be tied back to a new terminal. ABB is to supply the subsea equipment, while Allseas will install the pipeline and umbilical, and has subcontracted Stolt Offshore for subsea construction. ASI Corrib Joint Venture, in which Amec is one of the partners, will build the terminal. The field, which has reserves of around 800bn cf of gas, is due onstream in 2H2003. There will be five wells, which are currently being drilled by the semi-submersible *Sedco 711*.

Netherlands

The Dutch sector has produced a surprise this summer with the discovery by NAM of what is claimed to be the biggest gas find for 15 years – 11bn cm. It was made with exploration well K15-16 which found a 200-metre gas column. The gas will be landed in Den Helder, says NAM, suggesting the field will be tied back to the WGT pipeline system that passes through the block. The discovery lies close to the K15-FB platform.

A number of fields have come onstream in the Dutch sector in recent months. In January start-up took place on Wintershall's L8-P4 which has two wells and exports through the operator's Nordzee pipeline to the Uithuizen system. Further development has taken place of TotalFinaElf's K4 reserves with the start-up of the K4-BE satellite platform, also in January. Eventually five wells will be drilled on this field, which is tied back to K4-A.

In late 2000 Clyde's Q4 field was brought onstream using a refurbished topsides and jacket originally installed on Wintershall's K10 development – the first time a complete platform has been reused in the Dutch sector.

In August 2001 Veba achieved start-up open the Hanze oil field, which it has developed with a steel gravity-base platform. Crude will be offloaded into a dedicated shuttle tanker. By year-end two more wells – a producer and an injector – will be drilled, taking output to its peak of 30,000 b/d, when it will account for two-thirds of Dutch oil production.

Other projects are in the pipeline. Clyde's P6-D gas development is scheduled to start up in October 2001 while NAM is also moving ahead with its Neptunus project, which calls for three small platforms to develop gas reserves in the so-called A and B blocks, G16-FA and K2-FA. NAM intends to develop the A and B blocks with a single platform that can be relocated. Gaz de France has placed orders with Heerema for two wellhead platforms to develop new finds on K12 and G17.

Everyone Needs ...Standards

The quality of aviation fuel available in the UK

Surveys relating to the specification properties of aviation turbine fuels supplied in the UK have been carried out by DERA Fuels and Lubricants Centre since 1974. The 29th report covering the year 2000 survey* has just been published and a copy of the report has been placed in the IP Library.

The report contains a summary of the data of the specification properties of 2246 batches of aviation turbine fuel complying with Defence Standard 91-91 Turbine Fuel, Aviation Kerosine Type, Jet A-1 Issue 3. The information has been supplied by oil companies releasing main batches of aviation turbine fuel in accordance with Defence Standard 91-66 Segregation, Handling and Quality Assurance of Petroleum Fuels, Lubricants and Associated Products Issue 2. The data is expressed in the form of histograms and mean values. Graphical comparisons of the mean values over the period 1986 to 2000 are also made.

A number of changes and trends have been identified and are summarised right.

Trend data

Properties where the mean value has a rising trend	Properties where the mean value has a decreasing trend
Smoke point	Aromatic content
Distillation 90 % recovery temperature	Naphthalenes
	Flash point

Significant changes from 1999

Property	Change
Aromatics	Down 0.4% *V/V*
Specfic energy	Up 0.03 MJ/kg
Density	Down 2.0 kg/m^3

John Phipps, Technical Manager, Standards

Our website can be found @ www.petroleum.co.uk/tech/stds

The future is gas

Norway's hydrocarbon reserves are still on the rise but development activity is rather muted. *Nick Terdre* reports on the latest developments and highlights the increasing importance of gas in the country's energy portfolio.

The latest estimate from the Norwegian Petroleum Directorate (NPD) puts reserves at a total 13.8bn cm (86.8bn barrels) of oil equivalent – a 4.3% increase over the 1999 figure. In the last 11 years the estimate has risen by more than 60%, mainly due to an increase in discovered reserves achieved through technology development, the NPD points out.

Norway will remain a leading oil exporter for some time yet. Oil production is now almost certainly past its peak – currently running at more than 3.1mn b/d, but it is expected to remain above 3mn b/d for five years. But it is gas that represents the longer-term future, both for exploration and development. Oil reserves are estimated at 6.1bn cm, of which 64% (3.9bn cm) is in production or is approved for development and 36% (2.19bn cm) produced.

Above: Norsk Hydro's Snorre B floater came onstream two months early in June 2001.

This means that of the reserves in production or under development, 56% has already been produced. The estimate for gas is 7bn cmoe, of which 26% is in production or approved for development and only 10% produced.

Muted development activity

While the reserves outlook remains healthy, the investment picture has been redrawn since the period of low oil prices in the late 1990s, and the retrenchment that followed. Ironically, just before prices collapsed, the then government had delayed a dozen development projects by 12 months to prevent the sector overheating. The prospect of overheating would probably receive a warmer welcome today, but the reality is that investment looks unlikely ever to reach those exalted levels again.

From a peak of NKr79.2bn in 1998, investment slumped to NKr53.6bn in 2000 and, according to statistics, Norway, will be around NKr53bn this year – suggesting that the slump has levelled out. But spending on field development, at a forecast NKr18.4bn this year, is barely more than half of what it was in 1998. Nowadays, the major spend – NKr26.3bn this year – goes on operations.

A few large development projects still dominate the headlines – Grane (oil), Kristin, Snøhvit and Ormen Lange (all gas) – but the bulk of projects involve medium and small fields. Hopes for large discoveries are for the most part concentrated on gas prospects in the Norwegian Sea. The outstanding discovery last year was ExxonMobil's Bella Donna find in Norwegian Sea block 6506/6 which, though untested, is calculated by the NPD to hold 93.2bn cm of gas.

Nevertheless, interesting oil finds continue to be made. Last year Agip discovered the Goliath field in Norway's Barents Sea – the most significant oil find to date in that region – which it is to appraise this autumn. The NPD provisionally estimates reserves at 91mn barrels. And in July of this year, Statoil announced a significant discovery of light oil in the M structure to the north of Kristin in the Norwegian Sea.

Oil is well represented among the crop of fields coming onstream this year. Norsk Hydro's Snorre North (365mn barrels), which produced first oil in June, is a second stage of development of one of the country's large oil fields, while ExxonMobil's Ringhorne (280mn barrels), which came on stream in May, is a collection of nine separate deposits. The remainder are small fields with 40mn barrels or less – BP's Tambar, which came onstream in July, and Statoil's Glitne and Heidrun North, Shell's Garn West and Norsk Hydro's Visund North, are all due to start up later in the year.

This year's gas start-ups – all due in 2H2001 – comprise Statoil's Gullfaks Satellites II and Huldra, and Norsk Hydro's small Vale field.

The only large oil field currently under development is Norsk Hydro's Grane, with 704mn barrels, which is due onstream in autumn 2003. Development drilling was due to start in July – eight of the 26 producers are to be pre-drilled before the platform is installed in spring 2003. The other significant oil reserve approved for development is Norsk Hydro's Fram West, a subsea tie-back to the Troll C platform, which should also produce first oil in 2003.

Only a handful of other projects are looming – Statoil should submit a plan for development and operation (PDO) for Svale offshore mid-Norway before year-end, and for the nearby Falk field in a year or two. Norsk Hydro has the other parts of Fram and the Gjøa field lined up for development – both these fields also contain significant volumes of gas. So does Sigyn, for which Statoil submitted a PDO in mid-year on behalf of operator ExxonMobil – the field will be tied back to Statoil's Sleipner East field centre. Agip envisages developing Goliath with a production ship coming onstream in 2004, if appraisal goes well. BP's Skarv has oil as well as gas, but the company plans to test its recent appraisal well before deciding whether it has enough reserves for a stand-alone project.

Boosting production

A significant boost to future oil production will come from the further development of producing fields. Norsk Hydro already has approval for a third stage of development of the Troll oil reserves, Phillips has lodged a plan for a third stage on Ekofisk, and BP is preparing to develop the flanks of the Valhall field. Troll and Ekofisk are in constant competition for the role of Norway's leading oil producer – each is now in a peak production phase of between 330,000 b/d and 350,000 b/d. For Ekofisk, which came onstream in 1971, this is a remarkable feat.

Gas marketing

On the gas front it remains to be seen what effect the ending of the centralised marketing system in effect from 1 June has on development. In the eyes of the European Commission's competition authorities, the Gas Negotiating Committee (GFU) should have been wound up at about the time the European Union's gas liberalisation directive came into force in August last year. After months of foot-dragging by the Norwegian Government, Brussels decided to show it can bite as well as bark, and took the first step in a procedure which could see Statoil and Norsk Hydro, which ran the GFU, arraigned for distorting the free-market rules. If found guilty, each company could be fined up to 10% of revenues. It would be a bitter way of bidding farewell to a system through which Norway has established itself as a significant and reliable European gas supplier. (See also p3).

BP's Tambar platform is 'emissions-free.' Power, for example, is imported by subsea cable from Ula. Here, the jack-up *Transocean Nordic* prepares to start development drilling.

Now it is up to each licensee to market its share of a field's gas reserves. The switch should not on the whole prove problematic – although Norsk Hydro's new Chief Executive Officer Eivind Reiten has expressed concern that liberalisation could make it difficult to negotiate the long-term contracts needed to underpin the NKr30bn development of the giant Ormen Lange gas field. Because of the technically demanding nature of this development, Norway's first in seriously deep waters (850–1,000 metres), Norsk Hydro has pushed back its schedule by the best part of a year – it now aims to file a PDO only in 3Q2003, and achieve start-up at earliest in 2007.

Statoil recently announced its first directly negotiated gas sales contract – 1.6bn cm/y for 15 years to BP in the UK, starting in October. The gas – Statoil has yet to reveal which fields it will come from – could be routed via Vesterled, the new link installed by Norsk Hydro between Heimdal and the Norwegian Frigg export line which is due to enter operation in October this year.

Statoil itself has a series of gas developments lined up. Kvitebjørn has been approved for development and is due onstream in 2004, as well as a PDO for Kristin, aiming at a 2005 start-up, was submitted in August. Kristin will be the first of a string of fields located in the Halten Bank South area, which include Lavrans and the M structure. Kristin, which will act as a hub for the subsequent developments, will be developed with a semi-submersible platform exporting processed gas and condensate for export via the Åsgard facilities some 20 km to the northeast.

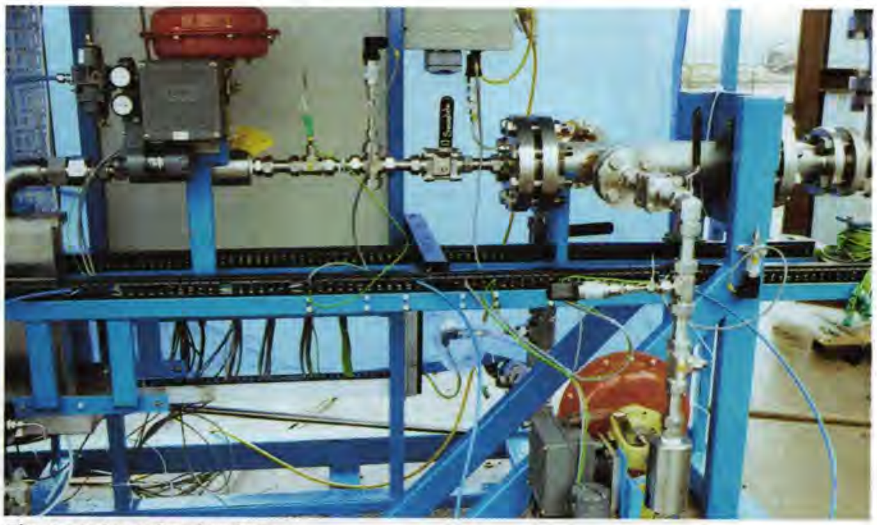
A number of other gas developments are close to going ahead. Statoil has recently filed a PDO for Mikkel, which is to be tied back to Åsgard, while Norsk Hydro is expected soon to apply to develop Oseberg Delta, which will be drilled from the Oseberg B platform.

However, Statoil's NKr40bn Snøhvit LNG project was put on ice in July due to Statoil's dissatisfaction with the fiscal terms offered by the Finance Ministry for the LNG plant. The company says it has signed sales contracts, but has not filed a PDO. Start-up had been expected in 2006.

** For approved field development projects in Norway, see the Norwegian field entries marked with an asterisk in the North Sea table listing on p14-16.*

Relieving the pressure

The requirement for providing pressure relief devices is mandatory in all pressurised systems. Most commonly, relief and blowdown valves or bursting discs are fitted to protect vessels and their associated piping by discharging to a suitable receiver or to vent or flare. *Stephen Richardson* and *Graham Saville* take a closer look at pressure relief sizing for two-phase hydrocarbon flows, including API recommended practices and the results of an extensive series of tests aimed at validating the homogeneous equilibrium model (HEM) used to size such flows.



The test rig at Spadeadam

The American Petroleum Institute (API) recommended practices have been widely used in the sizing of pressure relief devices for one-phase releases of hydrocarbon gas or liquid. The latest (seventh) edition of API RP 520 (published in January 2000) gives a method for sizing two-phase gas-liquid releases based on the homogeneous equilibrium model (HEM). The HEM assumes that the gas and liquid move at the same speed and are in thermodynamic equilibrium. API RP 520 uses an approximation known as the omega method to perform the calculations, but in practice it is as simple to do a full HEM calculation. Section D.1.1 of API RP 520 does, however, note that the method has not been validated by test.

In order to validate HEM, the authors and three colleagues from Imperial College in London undertook an extensive series of experimental tests at the Advantica (formerly BG) Spadeadam test site in Cumbria. The work was carried out under contract to the Institute of Petroleum as manager for the Relief and Blowdown Systems (RaBs) Joint Industry Project, which included participation by several companies operating in the North Sea and also by the UK Health and Safety Executive. The studies, including the experimental work, have been fully written up in *Guidelines for the safe and optimum design of hydrocarbon pressure relief and blowdown systems,* published by the IP in August 2001. (For details of how to purchase a copy of the *Guidelines*, see p26.)

Spadeadam tests

The Spadeadam tests were conducted using our own specially designed and constructed rig. Three hydrocarbon supplies were used:

- natural gas (essentially methane with some ethane);
- commercial propane (essentially propane and butane with some ethane); and
- condensate (essentially pentane to nonane with some decane to dodecane)

The supplies were independently metered (to within 1%), fed to the rig and mixed in different ways to determine whether or not pre-mixing of the streams had any discernible effect – it proved to have none. Restriction orifices of diameter 5 mm to 15 mm were used and pressures upstream from these ranged from 10 bar to 90 bar (150 psi to 1,300 psi). Flow rates were up to about 3 kg/s (10mn cf/d).

Conclusions

Comparison of predictions made using HEM and our experimental measurements shows that:

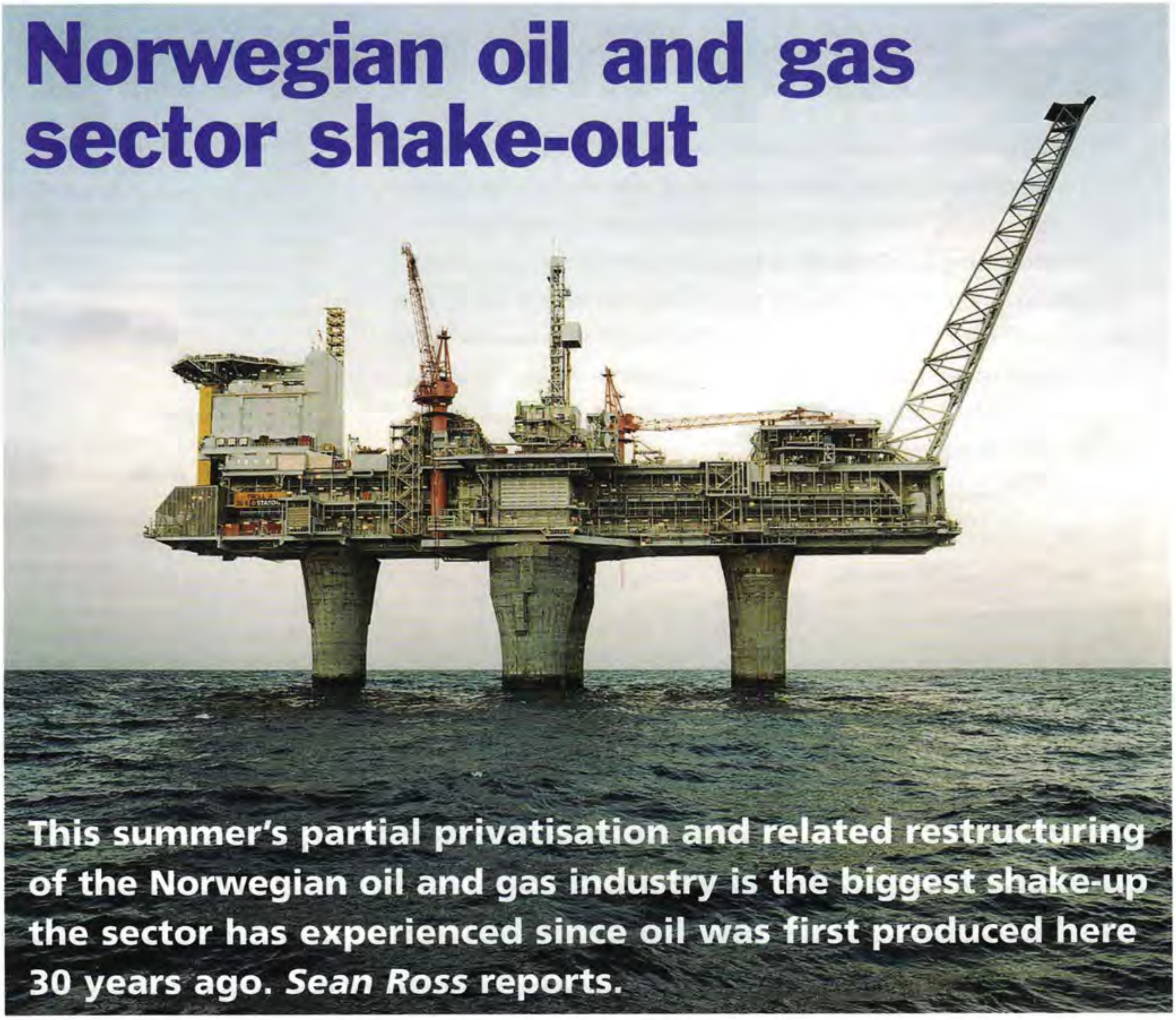
- Although there is a weak correlation of discharge coefficient with gas fraction (or quality), use of a discharge coefficient C_d of 0.93 in a fully-implemented HEM gives predictions of flow rate that agree very well with the measurements – the discrepancy is never more than 5% and is generally less than 2%.
- Use of the API RP 520 procedure (with the omega method and the API-recommended discharge coefficient C_d of 0.85) gives predictions of flow rate that agree fairly well with the measurements – the discrepancy is never more than 15% and is generally less than 10%.

Accordingly, we are able to recommend that HEM, fully implemented with an appropriate discharge coefficient, be used for sizing pressure relief systems for two-phase gas-liquid flows (see the full guidelines for details). It should be noted, however, that we have not validated HEM for:

- systems for which the upstream gas fraction (or quality) is very small; or
- systems in which the liquid is of high viscosity (such as, for example, a heavy oil).

Flaring a two-phase hydrocarbon flow

Norwegian oil and gas sector shake-out



This summer's partial privatisation and related restructuring of the Norwegian oil and gas industry is the biggest shake-up the sector has experienced since oil was first produced here 30 years ago. *Sean Ross* reports.

The State, following over a decade of pressure, has finally loosened its stranglehold on both the production and the sale of oil and gas from the Norwegian Continental Shelf. Statoil – formerly wholly owned by the State – has had 18.2% of its stock floated on local and international markets, while a further 21.5% of the State's additional oil and gas resources not held by Statoil has also been sold.

Furthermore, the sale of Norwegian natural gas to the Continent has been freed from 15 years of monopolistic control through the abolition, this summer, of the state's Gas Negotiating Committee (GFU), thus opening the way for the free marketing and sale of gas by individual producers.

Additional reforms, including proposals for a more encouraging tax regime, are expected to open the Norwegian Shelf up to new players, thus stimulating competition and ultimately production.

Statoil sale

Statoil debuted on the New York and Oslo stock exchanges in mid-June at NKr69/share, valuing the company at NKr151bn. The initial public offer (IPO) was three times oversubscribed, although mostly at the lower end of the NKr66–NKr76/share price band. A total of 18.2% of Statoil share capital was eventually floated, including the over-allotment option which was only partly exercised by the global coordinators in mid-July.

Of the total NKr27.18bn that was raised from the floatation, NKr13.0bn was transferred to Statoil's books, with the balance going to the already flush Norwegian State. Statoil is to use this NKr13.0bn to settle its outstanding debts with the State, picked up just prior to its floatation through the NKr38.6bn acquisition of 15% of the oil and gas assets held directly by the State. The State is still in the process of selling a further 6.5% of these assets to operators such as 44% state-owned Norsk Hydro and other international producers. It hopes to conclude the sale during the course of this year.

These directly held oil and gas assets have, following the sale, been transferred into a new, wholly state-owned company called Petoro. Its oil and gas assets are valued at over NKr500bn.

State coffers, meanwhile, have been swelled by NKr52.75bn, with an estimated NKr16.75bn still due from the outstanding 6.5% sale. These funds will be transferred to the already massive Government Petroleum Fund, which invests oil taxes and royalties in global equities and bonds. At the end of the 1Q2001, excluding revenues generated from this summer's sale, the Fund was valued at NKr425bn.

Above: The Norsk Hydro-operated Troll A gas platform opened in 1996. It is the only platform in the North Sea driven by electricity.

Gas sector restructuring

The Gas Negotiating Committee, or GFU, has been marketing Norwegian natural gas to Europe on behalf of local operators single-handedly since 1986. Both Statoil and Norsk Hydro, the two leading Norwegian operators, have been permanent members of the GFU, although other international producers have been free to join.

The GFU's abolition this summer was driven principally by the opening up of gas markets in Europe, and with it calls from producers on the Norwegian Shelf for increased freedom.

The European Commission (EC) is currently at odds with the Norwegian Government over the roles played by Statoil and Norsk Hydro in marketing gas to the European Union (EU) and the European Economic Area (EEA). The EU has sent the Norwegians a Statement of Objections, issued directly against Statoil and Norsk Hydro, suggesting an infringement upon EU/EEA competition rules. Both could face fines running into billions of kroner.

The Norwegian Government, meanwhile, is defending the establishment of the GFU, saying that management of petroleum resources remains with the national state for all parties of the EEA. It says that only through the GFU could Norway's offshore gas resources be developed in the most efficient manner possible. With the abolition of the GFU (although not permanently until the end of this year), companies on the Norwegian Continental Shelf are now free to initiate marketing contracts and other agreements between themselves.

The government has not, however, relinquished all control of Norwegian gas. It has established a new, wholly state-owned company called Gasco, which will take over the day-to-day transportation of gas to the Continent, including activities such as system operation and license administration.

A more competitive shelf

Included in the watershed changes to the Norwegian oil and gas sector this summer is a long called for revision of the current tax rules and regulations, which are seen as counter productive.

The new proposals are aimed principally at facilitating easier access to the Shelf for new and smaller oil and gas operators, and include elements aimed at preventing financial costs linked to businesses outside of the Norwegian Shelf from being deducted from Shelf income. This will prevent exploration companies needing to have maximum debt outside the Shelf before being allowed to receive interest payment deductions on debt held on the Norwegian Shelf.

The Statoil-operated Åsgard B gas platform came onstream in October 2000. It is the largest gas platform currently in production in the world.

Furthermore, the proposals aim to allow losses on the Shelf to be carried forward with interest which should stimulate new player participation; as well as to allow the transfer of losses in the event of a merger and to prevent losses from Norwegian land-based operations being deducted from offshore profits.

Lasting impact

Perhaps the most lasting impact of this summer's events will rest with the future role to be played by Petoro. Despite having shed 21.5% of its asset wealth, it still owns fully one-third of all the oil and gas resources on the Norwegian Shelf. However, it is still formally administered by Statoil on behalf of the government with regard to the management of its numerous licenses and the marketing and sale of its share of oil.

Importantly though, the respected Tore Sandvold, the former Director General with the Norwegian Petroleum and Energy Department, has been put in charge of Petoro. He is expected to play a more active, more independent role on the Shelf than Petoro's predecessor did.

Greater activity from Petoro, coupled with an improved tax regime and greater freedom for individual companies, will lead to further landmark changes on the Norwegian Shelf. Such changes are expected to include the ownership size of licenses, operatorship of fields and, ultimately, the remaining life of what is regarded as a mature shelf.

The Statoil-operated Åsgard field comprises the Åsgard A oil production vessel, the Åsgard C storage vessel and the Åsgard B gas platform.

Finding gas but not oil

Only limited data is generally available on oil and gas reserves and discovery rates. Over a number of years, the *IHS Energy Group has built up a definitive industry database. Each year it produces its *World Petroleum Trends (WPT)* report, which highlights key trends during the previous year as well as oil and gas exploration and production (E&P) data figures for the preceding decade (1991–2000). These figures cover activity in more than 150 countries. This year's report** – *World Petroleum Trends 2001* – shows that the industry continues to replace gas reserves but is increasingly failing to replace liquids reserves.**

This year's report shows that in the last decade just four non-Opec countries have replaced or expanded their reserves. Angola and Kazakhstan replaced production over six-fold while Colombia and Australia only managed to just about replace them; all the others failed to even replace reserves produced (see **Table 1**).

Opec producers appear little better placed having replaced less than half their production over the last decade, while the world (apart from the US and Canada) has replaced just 40% of production by new discoveries.

More new-field wildcats

Worldwide (excluding North America), new-field wildcat drilling bounced back from a 1999 low of 629 wells to a completion rate of 826 wells in 2000 – however, this was still fewer than any other year during the 1990s.

According to IHS its provisional estimate is that wildcat drilling discovered some 14.3bn barrels of liquids in 2000. This represents a 10% decline from the 1999 discovery level.

However, as in 1999, the 2000 total was skewed by one giant discovery – in this case, it was the Kashagan-East field, which is located in the Caspian Sea offshore Kazakhstan. At the time *WPT* was produced, oil reserves for the field were estimated at 6.4bn barrels recoverable, but the subsequent drilling of Kashagan-West, which may be in continuity with Kashagan-East, led the oper-

ator to announce proven reserves of 10bn barrels of oil. If this is confirmed, then 2000 will have seen the greatest volume of liquids discovered in a single year since the discovery, in 1991, of vast amounts of gas condensate in South Pars, Iran.

Booming gas discovery

Gas discoveries were high in 2000 – with an estimated 87tn cf discovered. This compares to 108tn cf discovered in 1999, but the 2000 figure will also rise with the success at Kashagan-West. Although both 1999 and 2000 showed a satisfactory increase over the trough period of 1992 to 1997, both years are eclipsed by the near 500tn cf of gas discovered in 1991, the year South Pars was discovered.

Reserves replacement

Table 1 shows the percentage of liquids produced, which were replaced by new field discoveries during the last decade. The countries chosen are the top 15 non-Opec producers for the year 2000. The US and Canada are excluded from this list because comparable data is not available.

Reserves are influenced by revisions but, according to IHS Energy Group's methodology, such revisions are back-

Country	Replacement (%) 1996–2000	Replacement (%) 1991–2000	Production (,000 b/d)	Production (b/y)
1 Russia	18	14	6,535	2,386.9
2 Mexico	15	22	3,450	1,260.1
3 Norway	37	45	3,365	1,229.1
4 China	49	57	3,245	1,185.2
5 UK	17	26	2,660	971.6
6 Brazil	202	164	1,255	458.4
7 Oman	39	42	960	350.6
8 Egypt	37	34	795	290.4
9 Kazakhstan	623	350	745	272.1
10 Argentina	35	36	820	299.5
11 Angola	653	403	735	268.5
12 Malaysia	19	46	805	294.0
13 India	8	20	785	286.7
14 Colombia	30	121	710	259.3
15 Australia	107	80	815	297.7
Top 15	**66**	**54**		
World (excluding US and Canada)	37	42		
Opec	35	47		
Non-Opec	41	36		

Note: These figures represent IHS Energy Group's estimate of volumes found in new-field discoveries and exclude any revisions made to fields discovered before 1991. The production figures are from the BP Statistical Review of World Energy 2001.

Table 1: Top 15 non-Opec producers in 2000, liquid reserves replacement from new field wildcat discoveries 1991–2000

dated to the time of the initial discovery. However, despite such revisions and the addition of new field discoveries, IHS Energy estimates that remaining recoverable reserves continued to decline throughout the decade as annual production rose from 68.5mn b/d to 73.6mn b/d. Remaining liquid reserves now stand at 1,100bn barrels compared with 1,207bn barrels of reserves at the end of 1991. During this period, the reserves-to-production (R/P) ratio has decreased from 48 years to 41 years, which indicates that the world's demand for oil continues to outpace its supply, and the gap between the two is widening.

Gas reserves hold steady

In contrast, while gas production has increased at almost twice the rate of oil production during the last decade, gas reserves have remained constant as new discoveries, when combined with several revisions, have matched production. Remaining conventional gas reserves are now estimated to be 5,876tn cf, hardly changed from the 1991 level. During the last decade, annual gas production has increased by 16% and the R/P ratio has declined from 75 years to 64 years, which indicates that worldwide gas utilisation will not be reserve constrained in the foreseeable future, but there may be regional differences and constraints.

Exploration performance

Although new-field wildcat drilling showed an upturn in 2000, the number of oil discoveries declined slightly, and the number of gas discoveries increased. The overall exploration success rate was 38%, which remained close to the 10-year average. The average discovery size in 2000 was 93mn boe, well above the 10-year average of 73mn boe.

Bright outlook?

A hopeful sign for future exploration is that in 2000 seismic data coverage, both 2D and 3D, saw significant increases over 1999 activity. Collection of 2D seismic was at its highest level since 1993 and 3D seismic coverage has continued to rise during the decade. In 2000, 3D increased at 12 times the rate recorded in 1991. New exploration awards, which had seen a dramatic decline in 1999, showed a significant increase during 2000 – a year in which the first awards for exploration off the Faroe Islands were made.

The IHS Energy Group claims to be the world's leading resource for information relating to oil and gas exploration, development and production activities. IHS Energy Group was formed in 1998 following the merger of Petroleum Information/Dwights, Petroconsultants, PI (ERICO), MAI Consultants and IEDS. Most recently, IHS Energy acquired QC Data's Petroleum Data Services Division and its AccuMap Enerdata Division.* (www.ihsenergy.com**)

The entire *WPT 2001* report is available for purchase from IHS Energy Group. *WPT* is also now available on CD-ROM or online, but paper copies can also be provided. For more information, please contact Louise Fry on Tel: +44 (0)1666 501237 or e:louise.fry@ihsenergy.com**

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Exploration glimmers in energy sector gloom

Brazil's third exploration licensing round – in which 34 of 53 blocks on offer received bids – was a moderate success in an otherwise crisis-ridden energy sector, writes *Maria Kielmas*.

Brazil's energy sector has been beset by problems in recent months. Ambiguous investment rules; a devaluing currency; political infighting at the highest level which has stalled much of the electricity privatisation process; next year's Presidential elections; continuing friction between the state oil company Petrobrás and oil industry regulator Agência Nacional de Petróleo (ANP); and Petrobrás's appalling safety record illustrated by the sinking of the P-36 production platform earlier this year – these are just some of the issues which have caused investors to reassess Brazilian risks.

Recent uncertainties about investment in Brazil came too late to affect the bidding in the third offshore licensing round and a number of notable signature bonuses were secured. The round collected R$594.944mn ($240.402mn) in signature bonuses with Phillips Petroleum posting the highest bonus of R$117.743mn ($47.669mn) for block BM-ES-11 in the Espirito Santo Basin. The next highest bonuses were offered by a consortium of Ocean Energy and Amerada Hess paying R$74mn ($29.96mn) for block BM-C-15 in the Campos Basin and R$59.040mn ($23.9mn) for block BM-S-22 in the Santos Basin.

Although nearly twice as many blocks were on offer in the third round than in the first and second rounds, the falling exchange rate has meant that the cash bonus total has remained nearly the same as last year (R$468.25mn/$259.85mn) and 1999 (R$321mn/$182.594mn). In common with the previous rounds, state company Petrobrás will participate in 14 of the blocks awarded and will act as operator of 13. The company spent a total of R$82.299mn ($33.32mn) on cash bonuses.

The predominance of Petrobrás in the bidding has not, however, been sufficient to cheer the Brazilian oil service sector which, for the past two years, has been pushing for both foreign operators and Petrobrás to be obliged contractually to use local companies. Successful bidders in the third round promised to use just 28.41% of local services for exploration, compared with 47% in the second round. However, foreign operators have not always stuck to their promises. For example, a Memorandum of Understanding between Enterprise Oil and US company FMC Modec to construct a platform for the Campos Basin Bijupirá-Salema field in the Gulf of Mexico rather than Brazil raised hackles. Enterprise said it chose the US company on the basis of price and delivery dates. In its original bid Enterprise promised to buy at least 34% of the $600mn project's goods and services locally.

The resulting furore prompted Enterprise to sign an agreement with local oil industry group Organização Nacional da Indústria do Petróleo (Onip) to increase the local content of its Campos Basin project. Onip also persuaded the ANP, the oil regulator, to say that if companies do not stick to their original promises of buying local services they will be fined. The fine will be proportionally smaller for those companies who already buy a large percentage of their goods and services from Brazilian firms. Despite the ANP's strictures, however, the third round's adjudication procedures did not give very great weighting to any bidders promising use of local services – some 85 points out of 100 were awarded to the highest signature bonus on offer for a particular block, 12 points were for promises to use local goods and services during the development phase and three points for the same approach during the exploration phase.

The ANP assured aspiring bidders during its third round roadshows that there would be no major changes to legal and fiscal terms. The exploration period for deep waters has been extended to a total of nine years, with each phase between two and four years. The biggest change, ANP said, would be speeding up of approval procedures and a clarification of oil export regulations. The deep well commitment has been removed and companies may now export oil freely, according to Article 6 of the petroleum legislation, except when the President declares a national emergency.

	1995	1996	1997	1998	1999	2000
Oil production (,000 b/d)	705	795	855	990	1,115	1,255
Oil consumption (,000 b/d)	1,500	1,600	1,730	1,800	1,805	1,825
Gas production (bn cm)	4.8	5.5	6.0	6.3	7.1	9.4
Gas consumption (bn cm)	4.8	5.5	6.0	6.3	7.1	9.4

Table 1: Brazil key statistics

Fourth round pending

A fourth exploration round is scheduled for the same time next year, followed by further annual bidding rounds. Four new basins will be opened up in 2002: Pernambuco-Paraíba located offshore the northeast coast; Pelotas, offshore of Rio Grande do Sul; and the onshore basins of São Francisco and Parnaíba.

The regulator remains bullish about future exploration activity, claiming that one-third of the world's marine seismic capacity is currently working offshore of Brazil. All but two of these seismic campaigns are conducted as speculative surveys, information that may have been welcomed initially by the government but not by prospective bidders who will have to pay the surveys' inflated prices. However, the spec survey may count towards the first exploration phase minimum work obligation

Ever since Brazil has opened the upstream to private sector investment in 1997 there have been some 125 announcements of discoveries by various companies. Nevertheless, the local rumour mill has suggested that some companies have been keeping quiet about their finds in the hope of bidding for adjacent blocks. Earlier this year Coastal Corporation, which controls El Paso Energy, had to issue a denial that it had made a gas discovery in the Pitanga Basin in central Paraná state. The denial had been prompted by an ANP inquiry. Had the company made a discovery and not informed the regulator it would have been fined $500,000.

Third-party pipeline access

ANP has spent much of its time targeting Petrobrás – the principal issue in dispute has been third-party access to the Bolivia–Brazil gas pipeline. The company is preparing a legal challenge to the ruling by the regulator to allow BG access for its Bolivian gas to the pipeline. The ANP had ruled that BG could transport 700,000 cm/d of gas through the pipeline between April and August 2001, increasing to 2.1mn cm/d from September 2001 to December 2002.

BG wants to extend this period to 2003, but Petrobrás claims there will be no spare throughput capacity at this time. This is because Petrobrás hopes to sell its gas to 14 planned gas-fired power plants which are expected to come online from the beginning of 2002 under the Programa Prioritário de Termoelectricidade (PTT), conceived as a fast-track scheme to contract new power generation capacity. Petrobrás currently transports 7.5mn cm/d through the line, whose capacity is 30mn cm/d, but is expecting to use the entire spare capacity by the end of the year.

A decision by the ANP last year to grant the Enron subsidiary, Enersil, third-party access to the Bolivia–Brazil gas pipeline for up to 1mn cm/d of interruptible gas supplies triggered much nervousness about competition throughout the Brazilian gas industry. The ANP's ambition has been to create a fully competitive gas market nationally by 2005, including open access to distribution networks.

Privatised gas distributors in the Rio de Janeiro–São Paulo area, who had signed contracts for monopoly franchises, are worried that their investments could prove uneconomic if the rules change to introduce full competition. But the real problem has always been Petrobrás' intransigence in preserving its preferential status in the Bolivia–Brazil gas pipeline project.

Enron spent eight months negotiating with Petrobrás for a transportation deal for interruptible, rather than firm, supplies and only succeeded because of ANP intervention. The problems from Petrobrás' point of view has been that it not only owns 51% of the pipeline operating company in Brazil, Transportadora Brasileira Gasoducto Bolivia–Brasil (TBG) and 9% of the Bolivian portion, Gasbol, it has guaranteed 100% of the finance of constructing both sides through contracting World Bank, Interamerican Development Bank (IDB) and state export credit agency loan guarantees. In the cases of the World Bank and IDB these guarantees were granted on the assumption that Petrobrás maintains its preferential status and were signed prior to the creation of the ANP in 1997.

Field	Operator	Start-up	Water depth (metres)	Prod'n facilities	Peak prod'n (b/d)
Marlim Sul I	Petrobras	Jul–01	1,000	FPSS	150,000
Marimba Leste	Petrobras	2001	?	FPS	?
Bijupura–Salema	Enterprise	2H2002	550	FPSO	70,000
Roncador I	Petrobras	2002	1,400	FPSO	100,000
Barracuda	Petrobras	2003	1,000	FPSO	150,000
Caratinga	Petrobras	2003	1,000	FPSO	150,000
Albacora Leste	Petrobras	2003	1,300	FPSO	180,000
Marlim Sul II	Petrobras	2003	1,000	FPS	200,000
Roncador	Petrobras	2003/4	1,900	FPS	200,000
Frade	Texaco	2004/5	1,000	FPSO	?

Table 2: Brazil – Future offshore oil developments

ANP Director General David Zylbersztajn, who is President Fernando Henrique Cardoso's son-in-law, has become famously disdainful of Petrobrás's woes, commenting that he has never seen any proof that Petrobrás is likely to go bankrupt if third parties have access to idle capacity on the Bolivia–Brazil pipeline.

The regulator is now trying to bring in an order to limit Petrobrás's stake in any future pipeline projects to 40%. Foreign operators, amongst them BG, have expressed interest in building a third gas export pipeline from Bolivia to Brazil. The second, shorter, gas pipeline to Cuiaba, was inaugurated earlier this year. The BG project foresees a line from Tarija in southern Bolivia, through Paraguay to Porto Alegre in Brazil. Completion is scheduled for 2004. BG has 4.6tn cf of gas reserves in Bolivia.

Gas markets

BG, together with Repsol-YPF and TotalFinaElf, is also interested in finding non-Brazilian export markets for Bolivian gas. Total proven and probable reserves in Bolivia now stand at 47tn cf, according to the Bolivian Government, giving the country the highest non-associated gas reserves in Latin America. The companies have announced initial studies of a $5bn–$6bn pipeline and LNG project which would transport Bolivian gas to a port on the northern Chilean coast where it would be liquefied and hopefully sold on the Californian market. But whether LNG produced by such a scheme would be competitive in a future US market is unclear. Previous studies of schemes to sell LNG from the Latin American west coast to Asian markets indicated such projects would be uneconomic at the time.

An alternative to the Brazilian market would give Bolivia a stronger negotiating stance over gas prices with Brazil. The Brazilian Government is keen to renegotiate down current prices it pays for Bolivian gas in an effort to tackle the energy crisis at home. The present crisis, which has forced the government to introduce power rationing, had been predicted over three years ago as electricity supply lagged behind demand while the government was unwilling or unable to clarify rules for energy investors. It took the worst drought in 70 years in a country where over 90% of power generation comes from hydro sources, and water reservoirs below 30% of capacity, for the reality to sink in. The power rationing began on 1 June 2001 and is expected to continue until at least next year.

Gas price pressure

Construction of gas-fired power stations has been delayed by the domestic gas price issue. Investors have been seeking some guarantee that they will not lose money as they are contracted to pay for imported Bolivian gas in US dollars while domestic tariffs are fixed in reais. Since the 1999 devaluation the real has been falling against the US dollar to an all-time low of R$2.47 in June.

The foreign exchange problem has been compounded by fears that Argentina's economic crisis will spill over to Brazil. The power generators are not allowed to pass through foreign exchange losses to customers and have been reluctant to commit to new gas-fired generation capacity for the past two years. The government had been toying with a number of schemes to ease the load for investors, including the creation of a devaluation insurance fund. So far this has not materialised even though the US state agency, the Overseas Private Investment Corporation (OPIC), has been working on a similar form of cover.

The latest (temporary) solution is that

Petrobrás will cover the foreign exchange variation in the costs of Bolivian natural gas, providing local power plants with a fixed price in reais for one year. These prices will be restricted to projects under the PPT programme, and are calculated on the basis of 80% of gas volumes being imported from Bolivia and 20% Brazilian production.

In the first instance the supplier will be Petrobrás. The company estimates that the gas price in reais will be calculated from a minimum base price of \$2.581/mn BTU, slightly higher than an initial base price estimate of \$2.475/mn BTU in late May. Currently, Petrobrás pays \$3.30/mn BTU for Bolivian gas while Brazilian gas prices vary between \$2 and \$2.20/mn BTU.

At the end of 12 months Petrobrás will calculate the net foreign exchange effect. Any losses to Petrobrás will be recouped over the following 12 months through a tariff increase, additionally adjusted for variations in the Selic (Sistema Integrado de Liquidação e Custódia) index which tracks Brazilian public sector bonds.

The Energy and Mines Ministry calculates that power generated by the PPT projects (some 49 plants are planned) would account for 7% of total annual power generation while gas prices represent 50% of the costs of power generated. Therefore, a 10% devaluation of the real would give an 8% increase in gas prices (taking into account the volume imported from Bolivia). This, in turn, would increase power generation costs by 4% (50% of 8%). The final increase in average electricity costs countrywide would be 0.28% (7% of 4%). By the time the electricity reaches end users via transmission, distribution and marketing processes, the net price increase would be 0.15%, a figure which the Ministry has adjusted to 0.22%.

Gas price renegotiation

Gas price renegotiation was on President Cardoso's agenda during his 26–27 June 2001 visit to Bolivia. Although Brazil's offtake at present is low, because of delays in building the new gas-fired power plants the long-term aim is to increase Brazilian purchases from their present 30mn cm/d to 150mn cm/d. The initial increase would be to just 40mn cm/d. Under the present take-or-pay contract Petrobrás is obliged to pay for 16.3mn cm/d of Bolivian gas but only takes 10.5mn cm/d, resulting in a daily loss of \$910,000. Both the oil and electricity regulators in Brazil have expressed a wish for this price also to be denominated in reais, rather than dollars.

At first, Bolivian President Hugo Banzer put a positive spin on the Brazilian proposal – saying in mid-June that it is in the interest of everyone to increase Bolivian gas prices, but this could also be done by selling larger volumes. Other Bolivian politicians were having difficulty maintaining a unified stance on gas prices, some suggesting renegotiations were inevitable, other saying they were impossible. All, however, ruled out changing the price denomination from dollars to reais.

Presidents Fernando Henrique Cardoso of Brazil and Hugo Banzer of Bolivia signed the Trija Declaration on 27 July 2001, under which Brazil would increase its imports of Bolivian natural gas by 10mn cm/d. Bolivian officials said that the price of the gas could be freely negotiated between the private sector buyers and sellers.

Prize-winning projects

In the lead up to the IP Awards 2001 Lunch on 2 October, *Petroleum Review* will feature a series of short articles from last year's winners. Here, *Shell* and *Schlumberger* describe how they are following up on their prize-winning projects and the impact on their staff of public recognition of the two companies' success.

Communication Award – Shell International

Shell International was awarded the Institute of Petroleum's Communication Award in 2000 for the Group's Corporate Identity Programme – an initiative that has gone from strength to strength ever since.

The communications programme is Shell's first coordinated global reputation management initiative to promote dialogue and engagement with stakeholders. The programme was created following extensive research and consultation amongst the full spectrum of audiences – from partners to critics, shareholders, media, academics, employees and others. What emerged was that Shell's policies, practices and principles were not clearly understood and that there was an appetite for greater engagement and explanation.

One of Shell's prime objectives is to demonstrate how it acts efficiently, responsibly and profitably within all businesses, as well as keeping an eye on the future by furthering research into alternative energy resources. This concern with the protection of the future, whilst remaining commercially responsible – identified as a commitment to sustainable development – allows Shell to earn increased license to operate by enhancing positive stakeholder perceptions of the way that the company goes about its business.

The Corporate Identity Programme made a great deal of headway in helping challenge society's perceptions of energy groups as well as communicating the Shell Group's activities and principles. Winning the IP Communication Award is just one positive outcome of this programme.

Solid progress

Since receiving the IP Award last year, Shell's Corporate Identity Programme has made solid progress. Staying with the PR-led strategy and tone, it has become even more innovative in approach, adapting global materials to local test markets in Ireland and Malaysia, and building on early tactics using research and learning to improve the content and its applicability. Further roll-out of the programme is expected in another five countries later this year.

One of the primary tools of engagement – the *Shell Report* – which provides an annual investigation of the Group's performance from an economic, environmental and social perspective – is now in its fourth year. Moreover, this groundbreaking publication has, for the first time, been circulated in three versions: a long-form report, a reduced sized précis report for shareholders, and a summary report designed specifically for wider distribution and interest.

New initiatives

Other initiatives that have been launched include:

- The Shell/Economist 2050 Writing Prize – an international competition to encourage people to write on their vision of the world in the year 2050. The competition is now in its second year, with the winning entries being published in *The Economist's* annual publication 'The World in .....'.
- The launch of the Shell Foundation – a charitable foundation established to support social investment initiatives in both developed and developing nations, involving partner organisations such as the World Health Organisation.
- A partnership with the IOC Commission for Sport and the Environment – fostering links between sustainability and sport.

Tom Henderson, Manager for Corporate Identity Communications, said: 'Winning the Institute of Petroleum's Communication Award for our work on communicating Shell's commitment to sustainable development meant a lot to us all at Shell. It has proved extremely valuable from a reputation and industry point of view. Recognition for the way in which Shell is actively listening to its stakeholders demonstrates that we are making progress in getting our message across, changing the way in which we do things – and learning, so that we are better placed for the future.'

Safety Award – Schlumberger Oilfield Services

Schlumberger was awarded the Institute of Petroleum's 2000 Safety Award for its Driving Safety initiative. 'Winning the prestigious IP Safety Award was a great honour for Schlumberger Oilfield Services,' reports Graeme Lawrie, QHSE Manager at Schlumberger. 'The company invests a large amount of time and energy into quality, health, safety and environment issues so it was especially rewarding to receive independent recognition of that effort.

Winning the award has definitely been of benefit to Schlumberger; first and foremost it generated increased internal awareness of the driving safety programme. The number of employees and contractors participating in the training programme rose significantly through the spring months. What's more, this increased awareness has no doubt helped in our efforts to maintain high standards in driving safety and UK driving safety performance has improved overall through 2001. Year to date statistics show we are currently under our average Automobile Accident Rate and we hope to see this average fall even further by the end of the year.

A number of our clients and competitors heard of our success and contacted us to get details of our driving safety programme. Our driver training provider, AcciDont, confirmed that they had seen a significant increase in the number of oil and gas companies using their training services during 2001, and although I could not say that this was due solely to the IP Award, raising awareness through the IP Awards certainly played a part.

Since winning we have made proud reference to our IP Safety Award when completing tender documents for our clients. Similarly, when our clients have audited us, many have commented on the accolade. Though it would be difficult to assert that the Award had been instrumental in gaining more business for the company, I am sure that the recognition that we received from it has helped to confirm our position as one of the leaders in health and safety in the oil and gas industry.

I'm sure from now on the Annual IP Awards submission deadline will be a regular slot in our calendar schedules!'

To purchase tickets for the IP Awards 2001 Lunch on 22 November 2001, please contact the IP Conference Department on Tel: +44 (0)20 7467 7100 e: *events@petroleum.co.uk*

Tengiz – a big gamble pays off

Christopher Pala **takes a closer look at the giant Tengiz field in Kazakhstan. The project has overcome a number of logistical and technological challenges since its discovery in 1979 – the most recent of which is the search to develop a means of reinjecting associated gas and hydrogen sulfide into the reservoir at 12,500 psi in order to boost oil recovery.**

When, in 1993, Chevron formed Tengizchevroil and took over operatorship of the giant Tengiz field on the Kazakhstani shore of the northern Caspian Sea, there were 90 wells, of which only 15 were working. Total oil production was 25,000 b/d – all exported by pipeline to Samara, Russia, and all gas production was flared. At this time, Kazakhstan's independence after two centuries of Russian domination was less than two years old. How reliable a partner the Government of President Nursultan Nazarbayev would prove – or whether it would even last – were open questions. It was a gamble for Chevron, but one that appears to be paying off.

Today, the Kazakhstan's economy is booming, opposition to Nazarbayev is fragmented and TCO (as Tengizchevroil is known) has increased production ten-fold to 260,000 b/d after investment of \$2bn. Self-financing its expansion since 1999, the company is currently building a further \$2bn worth of facilities to hike production to 415,000 b/d in 2005. Tengiz's light crude now costs \$3/b to lift.

CPC pipeline export

This autumn, TCO is starting to export its crude via a new pipeline to a terminal near Novorossiisk on Russia's Black Sea coast. The CPC (Caspian Pipeline Consortium) pipeline is the first foreign-built pipeline on Russian soil and represents a rare example of Russian–American cooperation. It will lower the cost of transport to a seaport from \$6/b to \$3/b and demonstrate that the huge Caspian reserves – long neglected by Soviet planners – can be profitably exploited and brought to world markets.

Some of the 7,000 crude-carrying railway cars that are being replaced by the \$2.6bn CPC pipeline.

'Chevron deserves a pat on the back for bringing the project where it is today,' said Robert Ebel, Director of Energy and National Security Studies at the Center for International and Strategic Studies in Washington, DC. 'When they went in, there was clearly a lot of risk involved – political, technical and mostly how they were going to get that pipeline built. But their real success will come only when they reach peak production.'

'Tengiz is still in its infancy,' TCO Director Tom Winterton recently stated. 'We believe that 700,000 b/d at the end of this decade is not unrealistic.'

Tough times

TCO's task so far has not been easy. The consortium – 50% Chevron, 20% state-owned Kazakhoil, 25% ExxonMobil and 5% LukArco of Russia – faced the world's deepest super-giant field, with a pressure of 12,500 psi and a hydrogen sulfide ($H2_S$) content of 17%.

In June 1985, a Tengiz well suffered a blowout in which one man was killed. It took Moscow six months just to acknowledge the existence of the blowout, even though a 700-ft high column of fire was visible from 90 miles away. Because of the $H2_S$, Soviet fire-fighters could not simply extinguish the fire with an explosion. 'The gas would kill every living thing within hundreds of kilometers,' *Izvestia* newspaper reported at the time. The well was capped a year later by Boots and Coots.

Rail-based export

As TCO started increasing production, it solved the problem of Tengiz's isolation and the limited capacity of the pipeline to Samara by harnessing 7,000 oil tank cars to export most of the increased production to four ports on the Black

Sea. It was the world's largest rail-based hydrocarbon transport system.

Initially, most of the gas was flared because Russia, the only nearby market, was awash with gas. The flaring caused indignation in the Kazakhstani public, which saw it as a waste. Eventually, some 3,000 gas cars were added to the rail network and 70% of the flaring was cut. Routine flaring should stop at the end of the year as gas exports increase by using the rail capacity freed by the switch to the CPC pipeline, according to Winterton.

Sulfur storage

The market for sulfur, an $H2_S$ by-product, was no better than the local gas market – it was lower than the cost of its transport. Over the years, Tengiz accumulated 4.5mn tonnes of sulfur, storing it outdoors in huge slabs 25 ft high and bigger than a football pitch. Every day a further 4,500 tonnes of liquid sulfur is sprayed with agricultural watering equipment onto the slabs, solidifying rapidly into a luminous, porous canary-yellow material that, surprisingly, hardly smells.

TCO is building a $40mn plant that, starting in 18 months, will turn the sulfur slabs into coated pellets, eliminating the sulfur dust that irritated the eyes of people living downwind from Tengiz when TCO tried unsuccessfully to crush it for export. The market for pellets, although weak, is stronger than the market for crushed sulfur, according to Winterton, but he admitted it would still need to rise in order to overtake the cost of transport by rail and ship. 'We plan to sell to the Mediterranean markets, but we don't expect it to generate a tremendous amount of profit,' he added with a measure of understatement. 'We'll have to see what the market allows us to do.' He curtly declined to speculate as to what TCO would do if the sulfur market failed to rise.

Real challenge ahead

But Winterton says the real challenge is going to be the planned reinjection of most of the gas into the wells TCO plans to start drilling in 2005 in a bid to improve the oil recovery rate. An early estimate of the recoverable oil was between 6bn and 9bn barrels; an updated estimate is expected at the end of the year. Reinjecting most of the gas and $H2_S$ will also cut down the production of sulfur.

However, the technology for reinjecting gas at 12,500 psi does not exist yet – so, until then, TCO will be experimenting. 'It'll be a new stretch of the tech' Winterton said with a grin.

Above left: With signs like these all over the facilities, its hard to forget that Tengiz sour gas contains 17% of lethal H_2S. Above right: One of the Parker rigs drilling at the world's deepest super-giant field.
Below: The slabs of sulfur at the Tengiz field: 4.5mn tonnes waiting for a buyer.

Obituary
Daniel Laignel

Daniel died last month aged only 55 and his quiet but insistent, well-informed and jovial presence will be sadly missed in trading and loss control circles.

Having qualified as a chemical engineer he joined the petroleum industry in 1976 as manager of 'Services et Transports' Lavera branch office. Following periods at S&T head office and in Gabon he joined SGS group in 1988 eventually becoming technical manager of Redwood France in 1990.

He was Elf Trading loss control manager since 1993 and a member of PM-L-4.

Daniel leaves a wife and two sons.

Crude oil marine measurement annual review

This article by *Paul S Harrison* – Consultant to the PM-L-4(A) Marine Oil Transportation Database Panel – presents findings from analysis of the 2000 data, updating the 1999 analysis which was reported in *Petroleum Review* in September 2000.

The PM-L-4(A) Marine Oil Transportation Database Panel collects and analyses worldwide crude oil shipping data with the general aim of improving loss control through a better understanding of loss patterns and trends. The losses noted are generally apparent rather than physical losses and result from the combination of fixed and random errors in the measurement systems used at load and discharge.

The Panel is currently developing an Internet-based version of the information presented here, together with additional data concerning crude oil marine transportation. The site should be ready to go live in 1H2002.

Membership of the PM-L-4(A) Marine Oil Transportation Database Panel has grown steadily since its formation in 1986. The following companies submitted data for 2000:

- AGIP Petroli
- BP Oil
- Caltex Trading Pte Ltd
- Chevron Company
- Chinese Petroleum Corporation
- Conoco
- Equiva Trading Company
- ExxonMobil Company
- Marathon Ashland Petroleum LLC
- Petrogal SA
- PMI Pemex
- Phillips 66 Company
- Repsol-YPF
- Saras Spa
- Scanraff
- Shell
- Statoil
- Sunoco Inc
- TotalFinaElf

Panel members submit their company data for analysis and an annual report is issued individually to all members. This report includes a confidential analysis of the individual company data together with a general global analysis of the entire annual data set. Reports are issued in both hard copy and electronic format.

Membership is open to all oil companies with data to contribute.

Database growth

The size of the database has increased over the years, due partly to the growth in membership but also as a result of existing members gathering more data from affiliates. The total number of voyages reported rose again in 2000 to over 7,700 and included a record 5.03bn barrels of crude at bill of lading (BOL). However, as shown in **Figure 1** there was a slight fall in total volume for voyages with complete load and discharge data which stood at 4.06bn barrels.

Global mean loss

The database includes well over one-third of the global shipped volume and is sufficiently large to be generally representative of the global situation and not to be unduly influenced by input from new members or by other minor structural changes.

The mean net standard volume loss (NSV) loss from the database from 1989 to 2000 is plotted in **Figure 1**. The overall improvement since 1989 is readily apparent, although global loss has shown no significant change since 1995. Mean NSV loss for 2000 was –0.195% (by convention losses are given as negative).

Loss comparison

Table 1 gives mean NSV loss and standard deviation for shipments of the most popular crudes in the database (20 or more voyages with full data). The mean of the reported API gravity is also given, together with the overall percentage loss based on total barrels shipped.

For comparison, figures for NSV

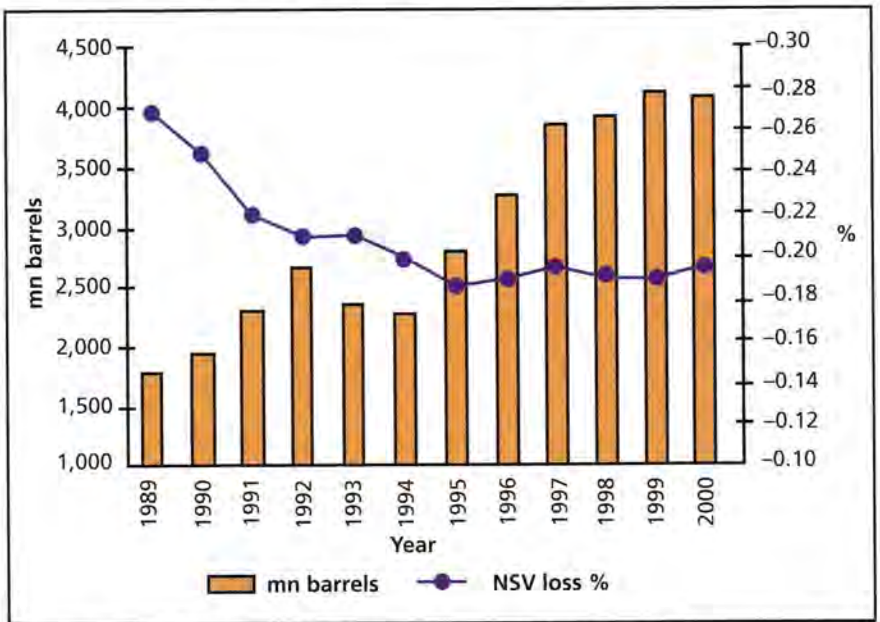


Figure 1: Growth in volume of database and average net loss of crude oil

Crude type	API gravity	Overall volumes (NSV)			Calculation by voyage					
					2000			1999		
					NSV loss %			NSV loss %		
		Total barrels	Barrels loss	Barrels loss %	Mean	Std dev	No.	Mean	Std dev	No.
Abu Safah	28.6	–	–	–	–	–	–	-0.11	0.18	23
Al Shaheen	31.4	–	–	–	–	–	–	-0.14	0.34	24
Alaskan North Slope	30.9	141,143,886	-23,065	-0.02	-0.02	0.22	219	-0.06	0.14	185
Alba	19.4	18,185,480	45,716	0.25	0.25	0.40	34	-0.31	0.49	23
Amna	37.8	29,771,012	-44,902	-0.15	-0.15	0.19	50	-0.23	0.22	50
Anasuria	39.1	13,436,795	-23,045	-0.17	-0.23	0.92	23	–	–	–
Arab Extra Light	38.2	120,628,948	-348,182	-0.29	-0.25	0.28	155	-0.21	0.23	172
Arab Heavy	27.8	86,844,463	-229,482	-0.26	-0.22	0.40	166	-0.16	0.52	122
Arab Light	33.0	264,540,508	-565,820	-0.21	-0.20	0.35	296	-0.19	0.29	245
Arab Medium	30.4	111,121,480	-267,446	-0.24	-0.20	0.37	165	-0.18	0.51	126
Asgard	41.3	41,290,231	-117,331	-0.28	-0.28	0.18	51	–	–	–
Azeri Light	34.8	–	–	–	–	–	–	-0.01	0.14	21
Bach Ho	40.7	18,194,018	-78,826	-0.43	-0.46	0.36	37	-0.41	0.39	49
Basrah Light	32.2	45,774,343	-37,494	-0.08	-0.12	0.42	38	-0.13	0.43	50
BCF 17	17.3	14,979,868	1,518	0.01	0.01	0.33	33	–	–	–
Belayim	28.1	20,047,685	-36,062	-0.18	-0.21	0.34	45	-0.08	0.30	45
Beryl	39.4	13,144,551	-59,924	-0.46	-0.46	0.58	24	–	–	–
Bonny Light	35.3	34,671,959	-61,929	-0.18	-0.18	0.22	38	-0.13	0.34	24
Bouri	26.3	20,176,463	-84,948	-0.42	-0.42	0.56	34	-0.28	0.50	32
Brent Blend	38.7	66,418,257	-37,013	-0.06	-0.05	0.16	99	-0.06	0.17	71
Cabinda	32.6	39,975,490	27,203	0.07	0.08	0.24	45	0.06	0.33	55
Cano Limon	29.6	–	–	–	–	–	–	-0.11	0.23	29
Cerro Negro	18.5	15,809,796	57,428	0.36	0.36	0.42	32	–	–	–
Cusiana	42.0	22,422,135	-60,991	-0.27	-0.27	0.22	36	-0.23	0.18	52
Danish	34.6	27,738,150	-73,800	-0.27	-0.27	0.22	54	-0.14	0.13	34
Draugen	40.3	55,360,862	-181,357	-0.33	-0.33	0.20	66	-0.34	0.15	69
Dubai	30.8	17,981,246	-23,471	-0.13	-0.14	0.15	23	-0.05	0.58	22
Duri	20.9	11,426,741	-20,932	-0.18	-0.17	0.41	32	-0.16	0.34	31
Ekofisk	37.6	112,991,401	-75,311	-0.07	-0.07	0.12	167	-0.09	0.16	125
Es Sider	36.5	19,273,688	-93,934	-0.49	-0.47	0.26	33	-0.45	0.34	33
Escravos	34.3	56,247,976	-42,186	-0.08	-0.09	0.25	53	-0.11	0.20	41
Flotta	37.3	33,815,258	-105,312	-0.31	-0.31	0.19	53	-0.26	0.25	46
Forcados	30.1	32,683,762	-2,478	-0.01	0.02	0.25	31	0.00	0.24	22
Forozan	31.1	35,076,998	-93,091	-0.27	-0.22	0.21	37	-0.15	0.45	65
Forties Blend	41.8	99,710,737	-138,392	-0.14	-0.13	0.18	143	-0.12	0.17	175
German Blend	33.4	18,007,632	-76,012	-0.42	-0.44	0.49	23	–	–	–
Gullfaks A	35.4	72,482,580	-290,614	-0.40	-0.40	0.20	85	-0.41	0.21	104
Gullfaks C	35.6	43,732,700	-205,713	-0.47	-0.47	0.37	53	-0.33	0.14	54
Harding	20.6	14,200,469	-49,260	-0.35	-0.35	0.26	25	-0.47	0.64	33
Heidrun	28.1	19,338,592	-1,225	-0.01	-0.02	0.16	31	0.08	0.26	46
Hibernia	35.4	15,165,361	-21,522	-0.14	-0.17	0.28	23	-0.05	0.30	27
Iranian Heavy	30.3	75,768,463	-168,421	-0.22	-0.16	0.59	92	-0.20	0.35	110
Iranian Light	33.4	62,101,661	-190,841	-0.31	-0.32	0.57	78	-0.22	0.56	73
Isthmus	33.3	8,121,586	-13,241	-0.16	-0.11	0.49	26	-0.13	0.51	40
Jotun	37.6	20,019,722	-31,750	-0.16	-0.16	0.49	26	–	–	–
Kirkuk	33.9	125,689,858	-304,290	-0.24	-0.24	0.27	140	-0.19	0.34	138
Kumkol	41.1	6,299,984	-19,436	-0.31	-0.28	0.38	21	–	–	–
Kuwait	30.7	52,841,512	-38,993	-0.07	-0.10	0.28	52	-0.15	0.17	46
Lower Zakum	39.8	13,077,850	-20,410	-0.16	-0.16	0.18	24	-0.33	0.17	64
Masila	31.3	39,208,475	-51,141	-0.13	-0.14	0.16	30	-0.17	0.12	34
Maya	21.6	213,667,884	-783,509	-0.37	-0.37	0.25	415	-0.27	0.34	309
Merey	15.7	12,429,811	17,721	0.14	0.14	0.29	26	–	–	–
Mesa 30	30.3	29,784,729	-31,013	-0.10	-0.10	0.29	55	0.06	0.28	69
Murban	39.4	49,098,177	-107,487	-0.22	-0.23	0.36	76	-0.26	0.22	107
Nanhi Light	39.5	15,267,483	-15,598	-0.10	-0.08	0.39	26	–	–	–
Nemba	39.0	22,921,056	-65,551	-0.29	-0.31	0.20	25	-0.38	0.30	33
Njord	42.1	16,552,359	-30,553	-0.18	-0.19	0.13	33	-0.04	0.13	21
Norne	32.6	37,754,262	-52,976	-0.14	-0.15	0.25	50	-0.09	0.42	66
Olmeca	38.6	98,356,578	-251,594	-0.26	-0.25	0.27	190	-0.19	0.35	180
Oman	33.0	50,418,480	-84,486	-0.17	-0.19	0.20	63	-0.27	0.25	102
Oriente	24.1	12,663,745	17,647	0.14	0.09	0.37	23	0.04	0.28	36
Oseberg	37.4	45,533,912	-96,074	-0.21	-0.21	0.14	61	-0.16	0.16	52
Qatar Land	41.0	–	–	–	–	–	–	-0.39	0.14	53
Qatar Marine	34.0	–	–	–	–	–	–	-0.26	0.16	45
Qua Iboe	36.9	69,787,449	-62,319	-0.09	-0.08	0.27	63	-0.25	0.48	77
Russian Export Blend	32.0	127,254,882	-260,408	-0.20	- 0.20	0.21	183	-0.21	0.24	256
Saharan Blend	46.2	42,129,325	-33,170	-0.08	-0.08	0.25	70	-0.10	0.22	58
Santa Barbara	37.5	11,224,876	-16,127	-0.14	-0.14	0.22	21	-0.08	0.17	29
Sarir	37.5	13,848,748	-35,740	-0.26	-0.33	0.43	26	-0.18	0.22	27
Siberian Light	35.5	13,093,668	-34,501	-0.26	-0.27	0.30	27	-0.18	0.30	29
Siri	37.4	8,144,300	-22,716	-0.28	-0.28	0.34	30	–	–	–
Sirtica	40.1	18,506,910	-43,567	-0.24	-0.23	0.15	31	-0.22	0.23	28
Souedie	24.2	14,703,984	-25,876	-0.18	-0.17	0.46	35	-0.20	0.30	36
Statfjord	39.1	135,655,937	-375,727	-0.28	-0.28	0.16	170	-0.26	0.22	185
Syrian Light	36.0	39,729,128	-109,167	-0.27	-0.27	0.25	71	-0.25	0.31	79
Tapis	45.7	–	–	–	–	–	–	-0.30	0.33	30
Tengiz	46.3	27,037,114	-134,018	-0.50	-0.51	0.35	63	-0.44	0.35	66
Thamamma Condensate	58.6	–	–	–	–	–	–	-0.24	0.19	22
Troll	27.4	30,881,943	-6,661	-0.02	-0.02	0.20	53	-0.14	0.18	31
Umm Shaif	37.1	–	–	–	–	–	–	-0.26	0.16	31
Upper Zakum	34.1	22,034,147	-46,866	-0.21	-0.25	0.19	28	-0.27	0.16	33
Zarzaitine	43.9	15,945,487	-51,630	-0.32	-0.33	0.16	25	–	–	–

Table 1: Analysis by crude oil type 2000

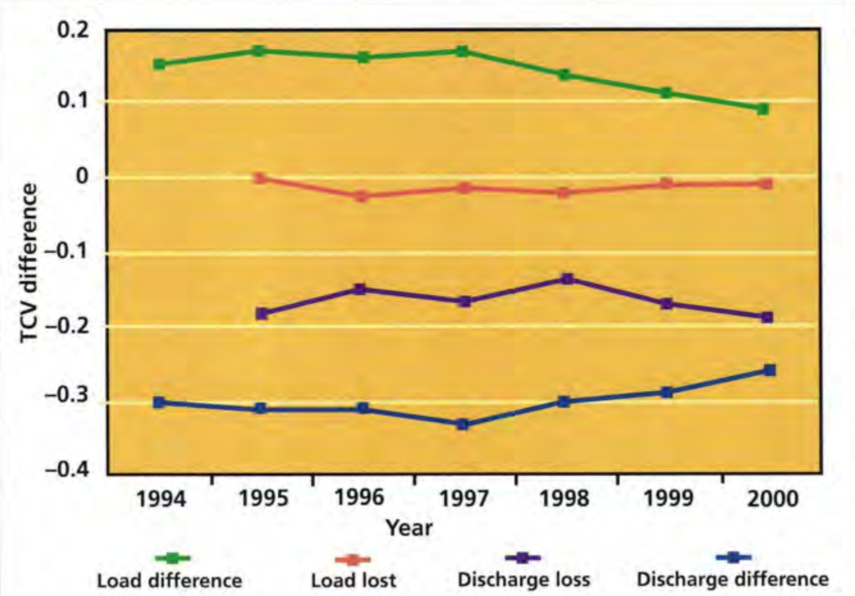


Figure 2: Comparison of load and discharge figures

loss calculated by voyage are given for 2000 and 1999. Where a grade is not reported for 2000 as the number of data sets has fallen below 20 the API gravity is given as the 1999 mean value.

Note that the data in **Table 1** is not 'table corrected' but based on original BOL figures. Where possible, for load ports using 'old' (1952) Table 6 or Table 54, corrected BOL figures are calculated using 'new' tables for comparison with outturns at discharge ports which also use the 'new' (1980) tables. The effect of using table corrected BOL data for specific crudes is shown in **Table 2**.

It should be noted that as the information in **Table 2** is derived from a smaller set of voyages than those used for **Table 1** (ie those with both corrected and uncorrected BOL figures) the actual mean losses will differ. **Table 1** should be used as a guide for typical measurement differences while **Table 2** gives an indication as to likely table difference. **Table 2** figures are based on a minimum of five voyages per grade.

Detailed loss analysis

In addition to NSV loss figures the database contains details of all measurements made through each voyage. This enables more detailed analysis to determine where losses are occurring and sets realistic performance limits for each stage in the measurement process.

Overall results for each of the main measurement differences are shown in **Table 3**, comparing figures for 2000 with those for 1999. As noted in last year's analysis, there is once again a reduction in the gain seen at load (load difference) which is balanced by a reduction in the loss seen at discharge (discharge difference). Key comparisons used in the analysis are as follows:

NSV and total calculated volume (TCV) losses are simple comparisons between bill of lading (BOL) and outturn figures. NSV is the volume of crude corrected to 60°F with sediment and water quantities (free and dissolved) deducted. TCV is the NSV plus sediment and free and dissolved water.

Load difference is the TCV difference between the ship after loading and the shore delivered volume. Discharge difference is the TCV difference between the the ship before discharge onboard quantity (OBQ) and the shore received volume. Load and discharge differences are not corrected for vessel experience factor (VEF). However, load loss and discharge loss figures are calculated making allowance for OBQ and remaining on board (ROB) (the difference between the TCV measured on the ship prior to loading and that remaining after discharge) and taking into account load VEF.

Ship loss or 'transit difference' is the difference between ship TCV measurements at the load port before sailing and at the discharge port on arrival.

Water loss is the difference between BOL and outturn water and sediment, adjusted for ROB/OBQ water difference where figures are available.

The trend noted in 1998 and 1999 continues with a further reduction in the load difference. This is balanced by a similar increase in discharge difference.

Comparison with the load and discharge loss figures, which are adjusted for VEF and OBQ and ROB, produces **Figure 2**. This shows that the gap between the uncorrected 'difference' figures and the corrected 'loss' figures is continuing to reduce. This results from a general reduction in VEFs and a reduction in OBQ and ROB volumes as shown in **Figures 3** and **4**.

Figure 3 shows fall in load VEF values over the past five years. This fall is apparent from the average by voyage values and remains when the average by vessel is considered. The fall is significant and may well be due in part to to the gradual introduction of new vessels

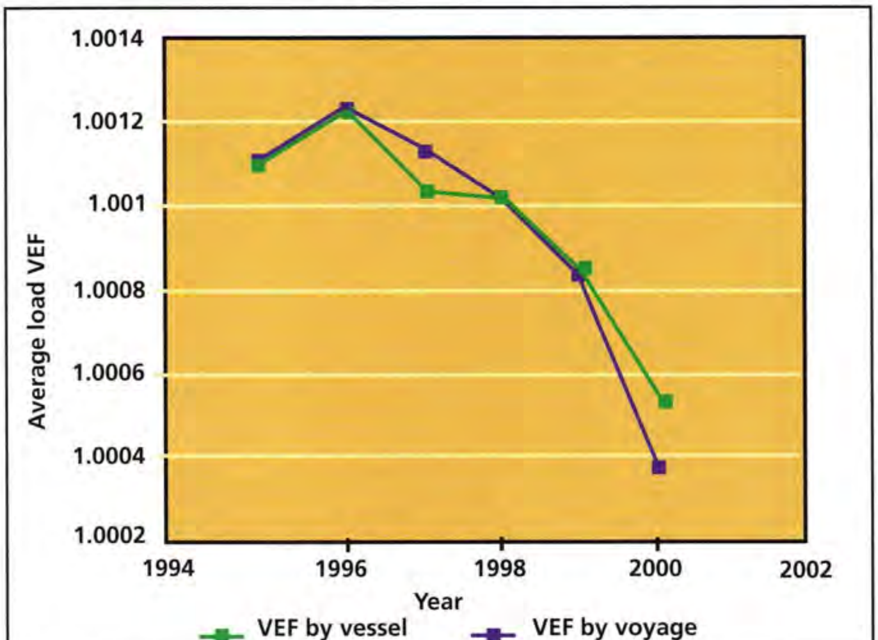


Figure 3: Vessel experience factor figures

Crude type	Mean NSV loss % Original	Mean NSV loss % Corrected	Table difference %
Arab Extra Light	–0.17	–0.02	0.15
Arab Heavy	–0.31	–0.25	0.07
Arab Light	–0.18	–0.02	0.16
Arab Medium	–0.20	–0.11	0.09
Arun Condensate	–0.40	–0.38	0.02
Attaka	–0.16	–0.10	0.05
Dubai	–0.09	0.03	0.12
Duri	–0.11	–0.15	–0.04
Lower Zakum	–0.17	–0.03	0.14
Minas	–0.10	0.24	0.14
Murban	–0.32	–0.15	0.17
Oman	–0.24	–0.07	0.17
Qatar Condensate	–0.22	–0.22	0.00
Qatar Marine	–0.24	–0.14	0.10
Ratawi	–0.20	–0.18	0.03
Saharan Blend	–0.08	–0.03	0.04
Senipah	0.08	0.18	0.09
Sharjah Condensate	–0.22	–0.20	0.02
Souedie	–0.32	–0.32	0.00
Syrian Light	–0.34	–0.28	0.06
Upper Zakum	–0.30	–0.19	0.11
Widuri	–0.38	–0.10	0.28
Zarzaitine	–0.31	–0.26	0.04
		Mean difference %	**0.087**

Table 2: Effect of table corrections on net standard volume loss figures for individual crude oils

	2000 Mean	2000 Std dev.	1999 Mean	1999 Std dev.
NSV loss %	–0.19	0.35	–0.19	0.35
TCV loss %	–0.15	0.33	–0.13	0.33
Load difference %	0.07	0.42	0.11	0.40
Ship loss %	0.03	0.23	0.04	0.24
Discharge difference %	–0.26	0.46	–0.29	0.44
Water loss %	–0.06	0.19	–0.06	0.20
OBQ–ROB difference %	0.02	0.13	0.03	0.15

Table 3: Global loss analysis

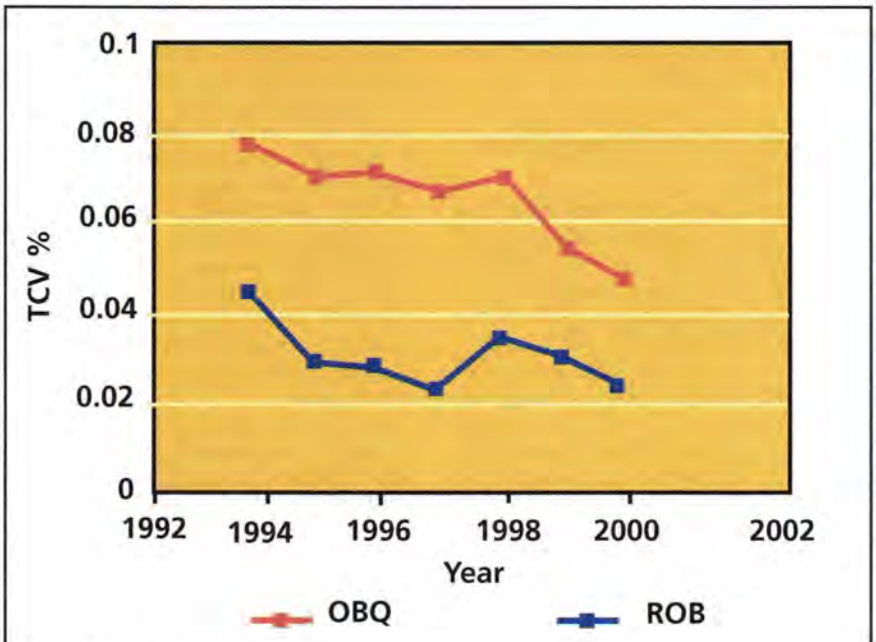


Figure 4: OBQ and ROB figures

with double hulls and more easily calibrated tanks.

OBQ and ROB (expressed as percentages of BOL and outturn TCVs respectively) have also both fallen, as shown in **Figure 4**.

The fall in ROB is not so marked as the fall in OBQ but it must be remembered that the ROB figures are as measured immediately after discharge – when much of the actual ROB is present as 'clingage' on the tank sides and is not measurable. The reduced OBQ and the reduced OBQ–ROB difference indicates that this clingage volume is reducing. Again, this could be due to increasing use of double hull vessels or perhaps a combination of this and more effective crude oil washing.

Conclusions

The 2000 data indicates that the loss reductions seen from 1989 through to 1995 have levelled off with average NSV loss for 2000 standing at –0.195%. This is higher than in 1999 but the change is not statistically significant.

The global loss pattern continues to change in relation to ship/shore comparisons and this would seem to be due to improvements in vessel design.

The database reduced slightly in 2000 in terms of volume for which full data was reported, but voyage numbers increased from 1999 as did volumes with BOL data.

Panel membership

All additional data adds to the value of the database and the information which is derived from it. The Panel has a target of 50% of seaborne crude trade which it hopes to achieve by 2005. A number of new members and prospective new members attended meetings in Stratford-on-Avon, UK, in November 2000 and in Sweden in May 2001.

The Panel meets twice a year and meetings are held in conjunction with those of the 'sister' panel, PM-L-4B, the Oil Transportation Measurement Panel. The next meetings will be held in New Orleans, US, on 6–8 November 2001 and will be hosted by Marathon Ashland. Prospective new members are welcome and are encouraged to contact John Phipps at the Institute of Petroleum for further details. Tel: +44 (0)20 7 467 7130, e: **jp@petroleum.co.uk**

Disclaimer: The IP as a body is neither responsible for the statements or opinions presented in this article, nor does it necessarily endorse the technical views expressed.

Controlling unwanted water production

The production of unwanted water is a growing problem in the oil and gas industry, costing operators billions of dollars every year. Halliburton Energy Services has developed both a new integrated approach to tackle this problem and a new organically crosslinked polymer known as H2Zero™. *Larry Eoff*, Conformance Principal Scientist, and *Paul McGinn*, Project Manager, ITP Conformance report on the new technology, that is claimed to have reduced water cut from an oil well from 15,700 b/d to 300 b/d in its most recent application in the North Sea.

Every year, oil and gas producers spend billions of dollars on unwanted water from producing wells. The negative impact on hydrocarbon production and the environmental impact of disposal of unwanted water are significant factors in reservoir economics. Unfortunately, the historical success rate for water control, or conformance within the industry, is also inconsistent because of the misapplication of treatment systems. Changing this success rate requires the use of the proper diagnostic tools to understand what is happening downhole (or within the reservoir), using this information to determine which treatments, if any, are feasible, and finally, placing the treatment. Developing and delivering fit-for-purpose solutions based on reservoir understanding is critical for controlling the production of unwanted water.

Halliburton Energy Services has begun to solve many of the problems associated with water conformance by using a more integrated approach to problem identification, reservoir understanding, treatment design and execution, and improved chemical systems. This approach has resulted in an extraordinarily high success rate – 98% – in the application of one of its newest chemical systems – an organically crosslinked polymer (OCP) known as H2Zero™ technology.

Integrated conformance process

A multi-disciplined approach is the key to the development of economic solutions to water control problems. This approach requires expertise in several areas, including diagnosis of the problem, development of a fit-for-purpose solution, and solution placement. Halliburton brings together conformance experts, reservoir engineers, log analysts, stimulation specialists, and completion engineers who work as a team to provide reservoir solutions to resolve water-management problems. In this approach, the experts perform the following tasks:

- Analyze existing data regarding reservoir characteristics, production history, and water-conformance problems to investigate potential treatments and to estimate savings that may result from the treatments.
- Perform downhole diagnostic services to gain further information on zonal isolation characteristics, critical reservoir parameters, and the mechanical integrity of the wells in the reservoir.
- Optimise treatment plans, refine economic estimates, and select the most cost-effective treatment plan for the reservoir.
- Implement, monitor, and evaluate the selected treatment.
- Use treatment-evaluation results to improve future treatments.

This integrated and multi-disciplined approach enhances success not only in the treatment of existing water control problems, but also by identifying pre-emptive actions that could prevent future problems.

H2Zero system development

The H2Zero system was developed to address the shortcomings of conventional water-conformance treatments. These include those associated with chromium-crosslinked polymer (CCP) shut-off systems that have environmental restrictions and technical limitations. CCP systems (that are based on polyacrylamide) have been widely used in water-shutoff applications worldwide, but research shows that CCP systems do not always completely propagate into the target zone. The limited stability of chromium crosslinkers may contribute to this incomplete propagation. At pH levels above 6 to 7 (typical in carbonate formations or sandstone formations rich in carbonate), the crosslinker tends to precipitate from solution, thus limiting the propagation of the gelant.

In contrast, the H2Zero technology is a unique crosslinked polymer system that relies on the polymer rather than on the chemistry of the crosslinker to create crosslinking delay. Therefore, the primary advantage of this system is its ability to propagate with no precipitation. Another important feature is its ability to perform in high temperatures, consistently performing at temperatures up to 300°F. Maintaining an integrated approach for identifying the proper applications for the polymer system, and developing and delivering proper placement, have resulted in a near-perfect success rate for treatments using this system.

Numerous lab-flow tests have demonstrated the H2Zero technology's ability to propagate through simulated matrix material. In these tests, stainless steel tubes were filled with packing material (sand, sand/carbonate, or crushed Berea sandstone) and one pore volume of the gel system was injected. The apparatus provided the option of using up to nine pressure taps along the length of the tube. Comparisons to a commonly used CCP system were made. As shown in **Figure 1**, the gel penetrated significantly deeper into a sand pack than the CCP system. In every comparison, the H2Zero system provided superior depth of penetration.

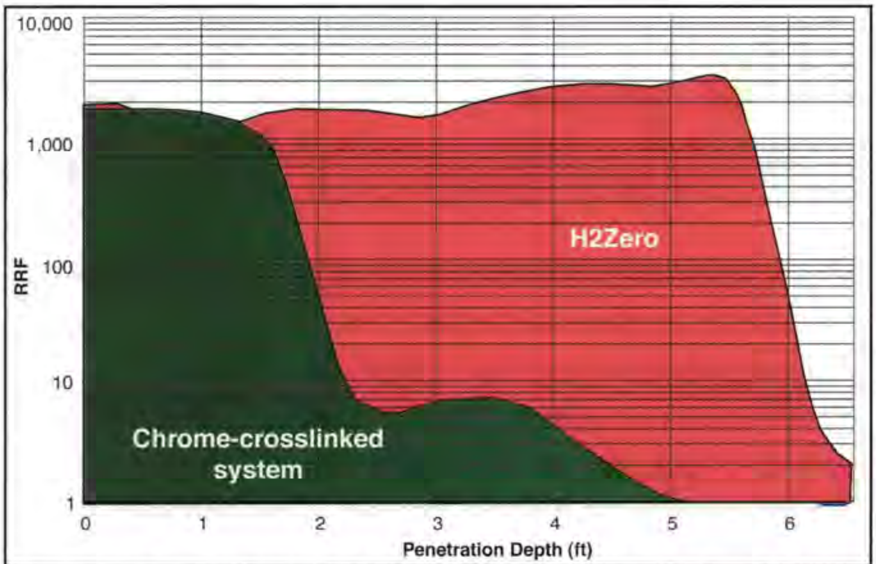


Figure 1: The H2Zero gel penetrated significantly deeper into sandpack in tests than the chromium-crosslinked polymer (CPP)

Case history

The integrated approach to conformance problems, along with the H2Zero gel system, has been extremely successful. To date, four jobs have been run in the North Sea – all four were hailed technical successes.

In the most recent treatment for Shell UK Exploration and Production, the water cut from an oil well was initially reduced from 15,700 to 300 b/d. The treatment, with 403 ft of perforations, is the longest horizontal, subsea, water-shutoff treatment completed to date.

The well, which was originally drilled in July 1984, was completed as a sidetrack of the original well in August 1999. Initial production rates from the sidetrack were as high as 25,000 b/d, with minimal water cut. However, three months later the water cut had risen to more than 50%. Subsequent well tests, over a nine-month period, confirmed that the water had risen to 65%, 72%, and finally 95%. After the last well test, Halliburton personnel evaluated the well by gathering fluid splits data for identifying potential crossflows and for determining the bottomhole pressures for the developing and planning potential water-shutoff operations.

Evaluation confirmed three zones on which water-shutoff operations would be performed. Injection water had broken through in the highly permeable Zone 1. In addition, water was crossflowing into Zones 2 and 3, below Zone 1 but above the first fault block. Since there were two further sequences of productive sands below the two fault blocks, H2Zero system water-shutoff operations were performed in Zones 1, 2, and 3.

The H2Zero treatments were pumped through 2-inch diameter coiled tubing into the three target zones. Each zone was isolated with a PES HE3™' retrievable bridge plug set below the zone before pumping the treatment volumes. After each treatment, a short production test was carried out to determine the effectiveness of the treatments before moving to the next zone.

The treatments achieved substantial shutoff across the three water-producing zones with 225 barrels, 19.5 barrels, and 16 barrels of the polymer system pumped into Zones 1, 2, and 3 respectively. The total production of unwanted water was significantly reduced from 15,700 b/d to less than 300 b/d. The payout time for the job was approximately one month. When compared with drilling another sidetrack, the water-shutoff operation saved the operator over $2.5mn.

Addendums

We would like to apologise for a few errors that crept into two recent editions of *Petroleum Review*.

Coal bed methane – July 2001

In the article on coal bed methane by Brian Warshaw on p15–17 it was stated the only UK company supplying methane commercially is Alkane Energy. However, John Garratt, Chief Executive of Octagon Energy reports that Octagon 'has been supplying methane gas commercially for nearly four years through the North Staffordshire Grid (NSG), which it brought from British Coal and British Gas.' He goes on to comment that: 'Octagon Gas, as a subsidiary to Octagon, supplies gas to consumers in the Potteries region of Stoke-on-Trent. Gas was extracted from the Silverdale mine into the NSG. When Silverdale Colliery closed Octagon installed extraction and pumping equipment to extract the gas from the abandoned mine and transport the gas via the NSG to its customers. It sells some 5mn therms per annum to the customers of NSG.'

Garratt also reports that the company, through its subsidiary Octagon (CBM) Ltd, 'extracts gas from the abandoned Hickleton mine and generates electricity through its 5.4 MW power station. The Hickleton generating station started generating electricity in December 2000 [see photo of Hickleton vent after development in July 2001 issue of *Petroleum Review*].

Octagon is also reported to hold 11 onshore licences covering some 1,200 sq km for the development of coal bed methane onshore the UK. The company is currently developing other sites for the extraction and utilisation of mine gas.

Enhanced oil recovery – August 2001

In the article on enhanced oil recovery by Adrian Gregory on p40–43 it was stated that 'Key to the development of IOR was its take-up in *1999* by BP's Wytch Farm oil field in Dorset.' This should have in fact said '1991'.

Life and limb – safety performance upstream

The International Association of Oil & Gas Producers (OGP) compiles information on the global upstream oil and gas industry's safety performance every year as part of its mission to promote the safe, responsible and profitable performance of this sector. Here, *Dr Don Smith*, Technical Director, reviews the data for the year 2000 – reported to be OGP's largest global benchmark to date.

'Encouraging' and 'frustrating' are the two contradictory words that come to mind when reviewing the most recent figures on the upstream oil and gas industry's safety performance.

A total of 39 companies reported on the safety performance of their upstream operations across 71 countries in Africa, Asia, Australia, the Middle East, Europe and the Americas. Among them, the companies recorded incidents during more than 1.6bn hours worked (see **Figure 1**) – equivalent to 800,000 working years and a 36% increase over the number of hours recorded for 1999. This rise in information is due to increased activity in the sector as well as growing industry recognition of the importance of recording safety information. The result – the most comprehensive database in the history of safety reporting.

Good news

First, the good news. The data for last year shows a drop in the lost time incident injury frequency (LTIF) from the previous year's figure (see **Figure 2**). This continues a decade-long improvement trend. In the year 2000, the LTIF of 1.88 per million hours worked was 41% of the level recorded ten years earlier.

When you drill down into the data, some of the performance figures become even more impressive. Contractors, for example, show an even higher level of improvement than average. Their LTIF stood at only 34% of its 1991 level. An even more dramatic improvement was recorded for offshore operations – where LTIFs were just 31% of their level a decade ago.

Clearly, lost time injuries are fewer and further between than they used to be.

Bad news

Now the bad news. These excellent results have to be balanced against the number of company and contractor fatalities in 2000. Last year, 148 people died in incidents associated with upstream activities. Twenty-nine of these people were third-parties; meaning they were not employed by either operating or contracting companies. When you factor these deaths – tragic though they were – out of the equation, the fatal accident rate for 2000 works out to 7.3 company and contractor lives lost for every 100mn hours worked. This rate is slightly worse than that recorded the previous year.

The most common causes of company and contractor deaths in 2000 were vehicle accidents and explosions and burns. A single incident, an explosion in Nigeria, occurred during the repair of a pipeline that had been damaged by sabotage. This incident alone accounted for 19 fatalities.

OGP's Executive Director, Alan Grant, is concerned: 'The most worrying conclusion from the 2000 figures is that over the past ten years there has been no real evidence that the upstream fatality rate has been declining. And what we must remember is that each fatality is much more than a statistic to be recorded in our report. It is a human tragedy, an individual life cut short; leaving family and friends bereft. Our industry can and must do better. If in the space of a decade – and despite all of our efforts – we haven't managed to reduce the rate of fatalities in our industry, we obviously will have to consider different new approaches to safety management.'

OGP is doing just that. A major workshop and follow-up report examined ways to improve joint company/contractor safety management systems. And OGP is currently focusing on the impact of human factors on safety performance.

Meanwhile, it is worth taking a closer look at the data to see what patterns emerge among each of the three key indicators of safety performance – fatalities, lost time injuries and the rate of total recordable incidents.

Fatalities

In the year 2000 there were 29 third-party fatalities. Twelve of these resulted from vehicle accidents. Boat collisions in inland waterways were the second-highest cause of third-party fatalities.

Among company and contractor personnel, there were 96 separate incidents – six of which resulted in more than one death.

Africa together with the Middle East accounted for almost half of the fatal

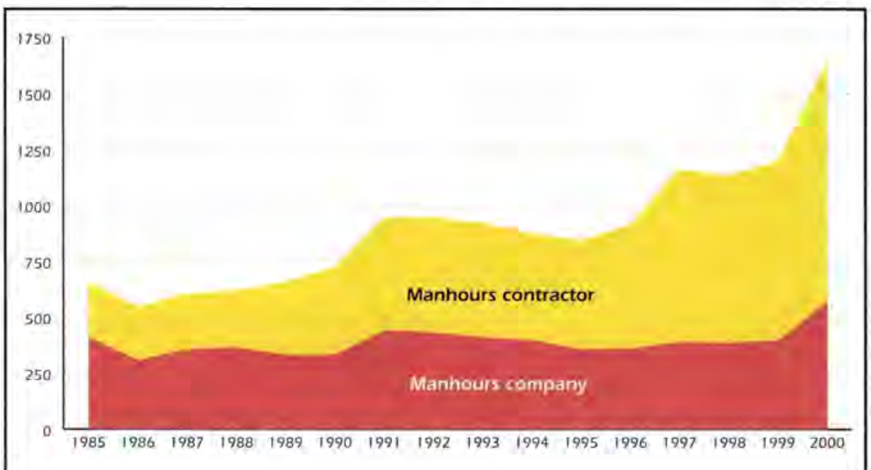


Figure 1: Working hours by contractor and company

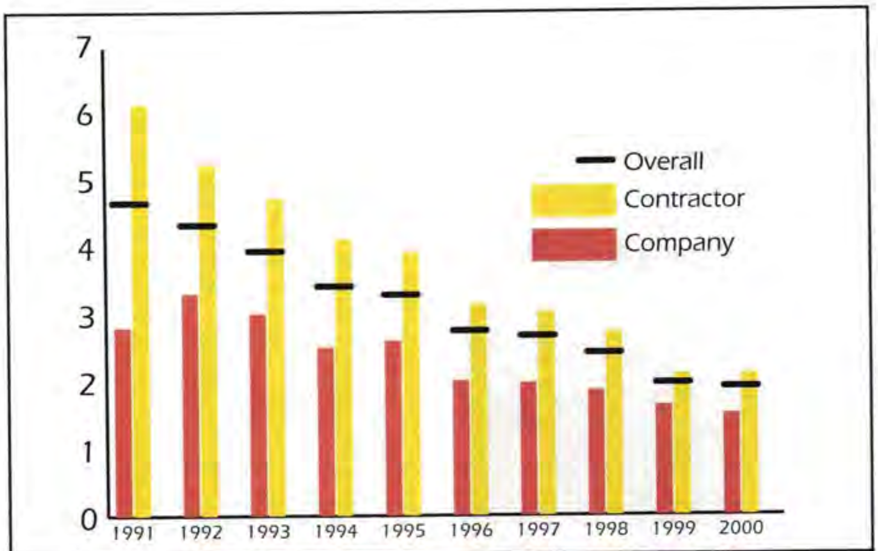


Figure 2: Lost time injury frequency – company and contractors

incidents recorded.

The overall fatal accident rate (FAR) was 7.28 company/contractor fatalities for every 100mn hours worked (see **Figure 3**). This was slightly worse than the 7.02 FAR that OGP recorded in 1999. The contractor FAR also deteriorated slightly – from 8.10 in 1999 to 8.66 in 2000. Company FAR, however, improved by 2% to 4.72.

The year 2000's onshore FAR of 8.03 was worse than the previous year's 6.12. In contrast, there was a dramatic improvement offshore, with a drop in FARs from 9.45 in 1999 to 4.7 in 2000. This was the lowest level since records began.

Vehicle incidents were the largest single cause of death, accounting for just over 26% of recorded fatalities. There were significantly fewer upstream deaths in air transport incidents in 2000 than in the previous five years.

Lost time injuries

There were 2,960 injuries (excluding fatalities) that resulted in at least one day off work in 2000. As in 1999, contractor employees suffered 72% of these injuries – although they only accounted for 65% of the hours worked.

On average, each injury resulted in 27.9 working days lost. For companies, the number of lost working days increased by 36% over the previous year to 37.3 days for each injury. In 1998 that figure was 18 days, indicating a doubling of the number of working days lost in the course of two years.

In contrast, the severity of lost workday cases among contractors showed a reduction of 19% to an average total of 23.4 days.

Total recordable incident rate

The number of total recordable incidents per million hours worked – encompassing fatalities, lost workday cases, restricted workday cases and those cases requiring at least some degree of medical treatment – declined in the year 2000 (see **Figure 4**).

Overall, the TRIR was 5.7 per million hours worked. This showed a 5% improvement – small but statistically significant – over the 1999 figure.

As usual, the data showed a higher incident of TRIRs for offshore operations than the onshore rate. This probably reflects the greater rigour in reporting offshore incidents. When these occur the only available medical attention is that provided by the company or contractor and so recording is done as a matter of course.

The story in full

OGP's complete report on global safety performance indicators for 2000 encompasses 94 pages of text, graphics and tables. It includes a list of all the companies that participated in the report, though anonymity is preserved about detailed results. Visit the OGP website at **www.ogp.org.uk** for the study in full, as well as other reports on a wide range of topics dealing with health, safety and upstream representational issues.

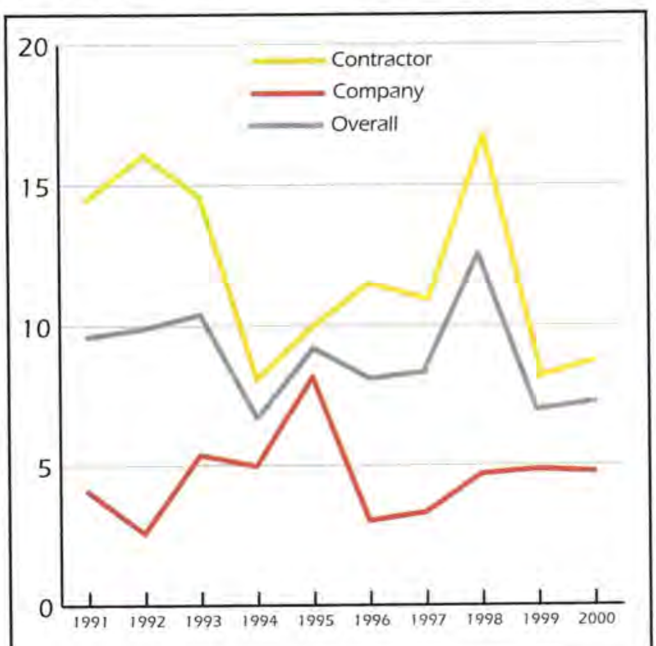


Figure 3: Fatal accident rate – per million hours worked

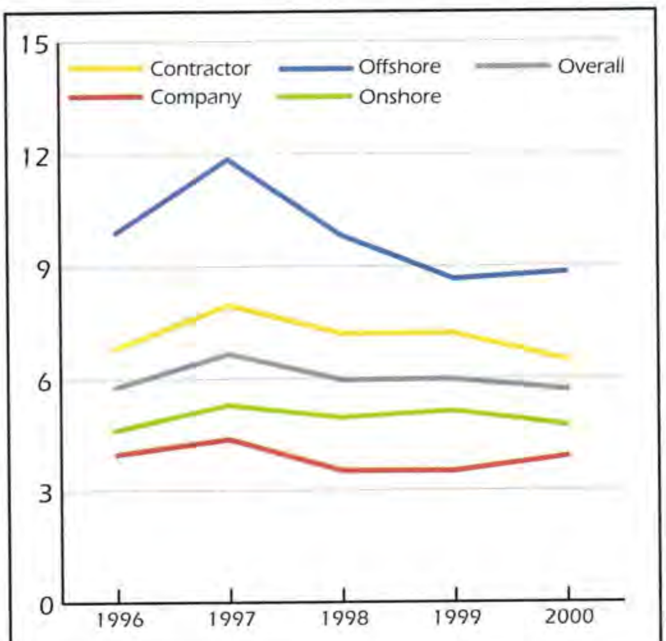
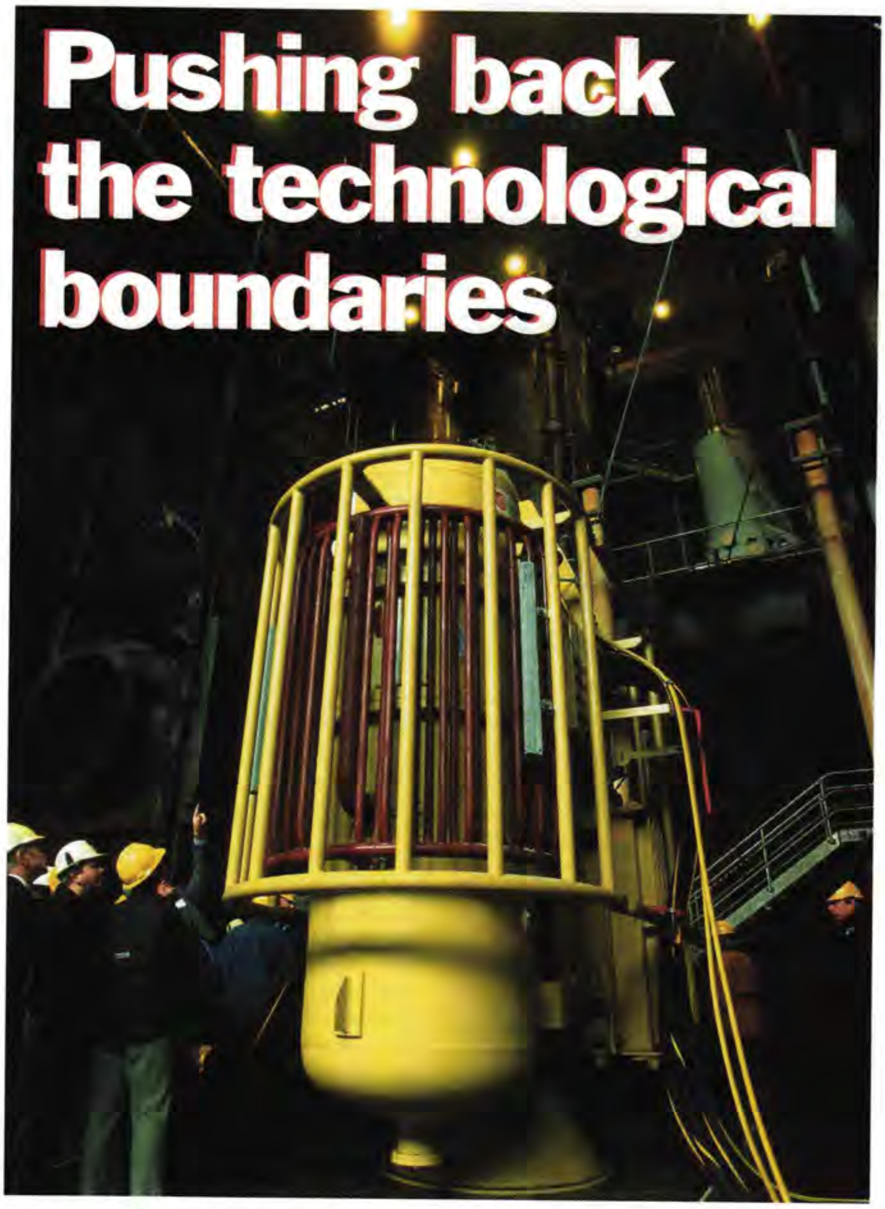


Figure 4: Total recordable incident rate

Pushing back the technological boundaries



Among the latest initiatives undertaken by ABB is the formation of a joint venture that aims to provide a one-stop shop for subsea production requirements. The Swedish/Swiss contractor is also working hard to push back the technology boundaries in key areas such as deepwater production platforms and subsea separation, and scoring important successes in such as its equipment supply contract for Shell's Bonga project testifies. *Nick Terdre* reports.

Above: The subsea frequency converter developed as part of the Sepdis project and which is undergoing endurance testing in Norway this summer.

Syntheseas, a new joint venture (JV) company set up by ABB and Schlumberger, is a name that looks set to become familiar to oil companies looking for cost-effective solutions to subsea developments. The company is interested in working closely with clients to develop 'total systems', rather than 'widgets', Alan McGovern, the new company's Vice President for Marketing and Technology, told ABB's annual seminar on subsea technology which was recently held in London.

A limited liability company with offices in London, Aberdeen and Houston, and with representation in Norway, Syntheseas has been launched at a time of almost exponential growth in subsea completions – so it has no shortage of potential market opportunities to aim at. The move was prompted as both sides of the JV independently concluded that there was a lack of true integration from the reservoir to the production facilities which was the source of inefficiencies.

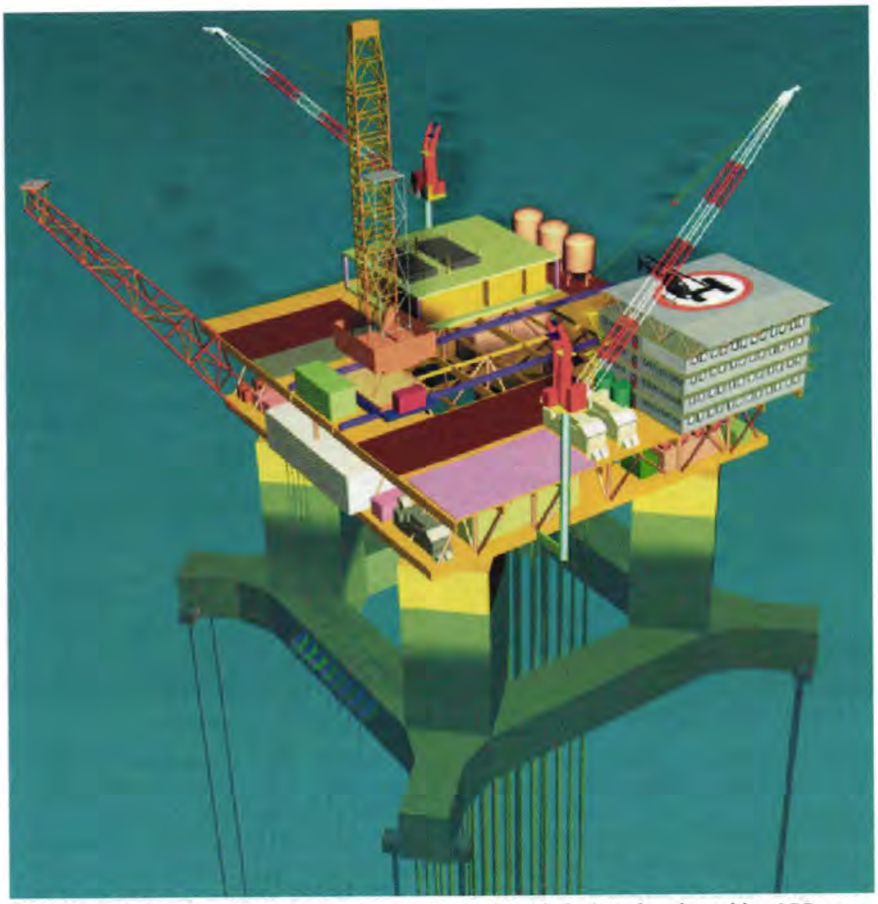
The two companies bring complementary skills to the JV – Schlumberger its seismic and reservoir evaluation capabilities, drilling engineering, drilling and completions expertise and field management expertise; and ABB its downhole technology, subsea production and process equipment. The JV will be able to offer a life-of-field approach, running through all phases from seismic to abandonment, and a scope of operation from the reservoir to the point of delivery of the reservoir production fluids, whether this be a riser, FPSO or shore delivery point of an offshore pipeline. The few gaps in the company's range of provision, such as drilling and installation operations, will be filled by making preferential arrangements with relevant contractors.

Field development opportunities are being missed, McGovern said, as can be seen from the success of Logic's Satellite Accelerator initiative in the UK, under which operators allow contractors to look for cost-effective means of developing marginal fields where they themselves have failed to come up with a viable solution. Syntheseas sees a role for itself in occupying this space and, in conjunction with operators, identifying solutions that will fly. In an initial stage it is targeting tie-back prospects – it wants to start small and work its way up to larger challenges – but the company's service is equally applicable to larger fields.

The JV should not be seen as just a super EPIC contractor – by combining its input with the client's, a lot of additional value will be created. The use of one contractor will also allow development to be speeded up, primarily through reducing the number of interfaces. Added value will also come through the integrated scope of supply, a simplified contracting strategy, and reduced contingency provisions.

The close relationship Syntheseas looks for with clients is also reflected in the financial commitment it is ready to make. It will be prepared to look at financing its own scope of work, and having some payments made contingent on business performance. It is also prepared to take some of the risk related to using new technology. On the other hand, it is also quite clear-minded about what it is not prepared to do – it will not take an equity position in a field, it is not interested in taking on the strategic management of a client's portfolio, it will not make any investment which lacks a link to services provision, it will not expose itself to exploration or appraisal drilling risk, and it will not take on liability for catastrophic risk.

Syntheseas has met with a good response to its initial marketing campaign. According to McGovern it is currently in dialogue with more companies than it can comfortably handle, most of them small but including a couple of good size. Geographically it is focusing its efforts on the North Sea, West Africa and, to a lesser extent, the Gulf of Mexico.



Top view of the extended tension-leg platform (ETLP) design developed by ABB as a dry-tree concept for deepwaters.

Bonga – a new landmark

While Syntheseas is an expression of ABB's ambitions for a life-of-field involvement, the company continues to make its mark as an equipment supplier. The EPC contract it recently won to supply the subsea systems for Shell's Bonga development offshore Nigeria is the company's biggest ever. Worth $180mn, the scope includes 29 subsea trees, 37 control pods, five subsea manifolds, eight gas-lift risers, running tools, ROV tools, production umbilicals and more. The equipment will be installed in water depths of 1,000 metres and more. Deliveries are due to start next year and will not be completed until 2010.

The main challenge for the company is not so much technical as logistical, with activities to be managed across a variety of locations – trees (Scotland), control systems (England), manifold engineering, gas-lift risers and umbilicals (Norway), manifold construction (Spain), hydraulic controls and jumpers (Houston). Systems integration testing will take place in Scotland and Norway, and the whole contract will be managed by a joint client/ABB team based in Houston. The local base for deliveries will be ABB's subsea operations base at the Onne Free Port in Nigeria which will be substantially expanded.

The company's recent delivery to Amerada Hess's Conger development in the Gulf of Mexico was a lot smaller, but also significant in that it marked the world's first delivery of a 15,000 psi horizontal tree well control package. Incorporating ABB's WITS technology, the

Troll Pilot – reported to be the world's first subsea separation systems.

system will now be supplied for six wells in Enterprise's Corrib project offshore Ireland. The technology development reflects another important trend – the increasing number of high-pressure fields coming forward for subsea development.

Deepwater platforms

Part of the reason for the amazing growth in subsea completions is of course the advance into ever deeper waters. Here also ABB is a committed player, and Chris Braithwaite, Head of the Floating Production Systems Business Unit, reported on the latest moves in the design of the next generation of deepwater platforms, notably the extended tension-leg platform (ETLP) and the single-column floater (SCF), ABB's version of the spar concept.

The ETLP is now at a very advanced stage – it has moved beyond the scantling design and has been offered to projects such as Kizomba offshore Angola, Agbami offshore Nigeria – both in water depths of around 1,300 metres – and Matterhorn in the Gulf of Mexico. A contract award could come in the not too distant future, according to Braithwaite.

One of the advantages of both TLPs and SCFs is that they offer the possibility of dry wellheads and the benefits that go with them, such as ease of well intervention. The ETLP is an evolution of the conventional TLP concept, and all the key critical systems – topsides facilities, drilling system, riser system, deck and hull structural systems, and mooring system – are extensively field proven. The ETLP can have a hull configuration with either four or three columns. The 'extended' in its title refers to the outward extension of the pontoon base at each corner, to which the tethers are attached.

Compared with a conventional TLP, the ETLP is claimed to offer weight savings of around 40% – which at the end of the day translates into cost savings. Its structural weight efficiency – the ratio of weight of payload to weight of platform – is high, ranging for instance from 0.8 to 1.3 for Gulf of Mexico and West Africa applications respectively.

The design also makes possible a shorter and less complex installation operation, which is therefore less liable to run into weather problems. For installation purposes, temporary stability modules are installed by each column during hull fabrication. These provide the necessary waterplane areas to keep the unit stable until it is installed, after which they are removed. Like floaters in general, the ETLP can be completely integrated and commissioned inshore, which makes it favourable for installation in remote areas such as West Africa where support services have to mobilise over long distances.

Although less advanced than the ETLP, the SCF is beyond the stage of model tests and ABB is now working with another company to have it ready to bid for an upcoming development in the Gulf of Mexico. Its main difference from a conventional deep-draft caisson vessel is its extended base, which provides enhanced stability during tow-out and reduces the effects of vortex-induced vibration. The SCF also has a reduced length, which means less steel is required for the hull, which can be built as a single unit, and built and transported in vertical mode. The SCF is well suited for ultra-deep waters of up to 3,000 metres.

Both the SCF and ETLP are viable new solutions for deepwater developments in provinces such as West Africa, offering significant cost and schedule advantages over earlier generation dry-tree completion concepts, ABB claims.

Subsea processing and power

ABB stole a march over its competitors by winning the contract to supply the world's first subsea separation system in the shape of the Troll Pilot. Unfortunately the unit has been unable to function properly due to an earth fault in the high-voltage connector which supplies the power to run the water injection pump. While the separation system has worked well, achieving a water quality of down to 140 ppm of oil, it has not so far been possible to pump the water down a dedicated injection well as planned. In July ABB planned to retrieve parts of the system for repair or replacement and have the whole system ready for operation by mid-August.

The earth fault in the HV connector occurred when cracks developed in the epoxy moulding due to lack of hardening. The connector has now been redesigned and extensively tested, according to Åsle Solheim, Head of Business Unit Subsea, Norway, and the moulding in the male plugs in both the pump and the umbilical termination head (UTH) was to be replaced. Changes were also to be made in the control system, with the replacement of the hybrid coupler by separate optical and electrical couplers, replacement of the UTH, and a change of insulation material in the coupler. The subsea control modules were also to be modified to suit the new couplers.

Meanwhile endurance testing is underway of the subsea frequency converter that is a critical component of Sepdis, the subsea electrical power distribution system (see photo p42). The tests are being carried out at Framo Engineering's test dock near Bergen, Norway. The converter has been tested for typical load capability, varying load and speed up to overload and overspeed situations, and according to ABB has passed with flying colours. The system will make it possible to provide power to subsea consumers, transporting high-voltage electricity to run electric motors, pumps, and so on, at variable speeds and loads. The Sepdis development programme is a joint industry project involving ABB, Framo and the Ormen Lange license (Norsk Hydro, Shell, BP, ExxonMobil and Statoil).

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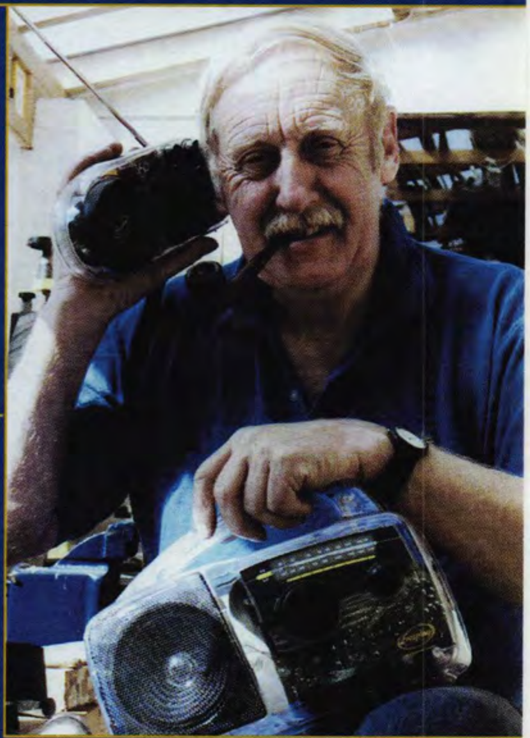

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Breaking fresh ground...

Photo: Emma Parsons

FPSO first in 'Iceberg Valley'

Photo courtesy of PetroCanada

Jeff Crook reviews progress on the Terra Nova field offshore Newfoundland and explains how the development of a carefully conceived ice management plan is vital to the success of the project.

Icebergs drifting down on currents from Greenland pose an enormous hazard to oil field development on the Grand Banks offshore Newfoundland. The first approach to this problem was to design a platform that was large and strong enough to resist an iceberg impact – the final solution adopted for the Hibernia field (see *Petroleum Review*, September 1998).

Now an ice-strengthened floating production, storage and offloading (FPSO) vessel is to be used for the Terra Nova field, with special features to allow it to move off station when ice hazards threaten. This will be first FPSO vessel installed in ice prone waters and the success of the concept depends on a carefully conceived ice management plan. The Terra Nova development is being carried out by an alliance whose partners are: PetroCanada, AGRA Brown and Root, Halliburton Energy Services, FMC Offshore Canada, PCL Industrial Constructors, Coflexip Stena Offshore Newfoundland and Doris Conpro Offshore.

The Terra Nova oil field is the second largest oil field off Canada's East Coast, after Hibernia, and has estimated recoverable reserves of around 370mn barrels of oil. It is located 350 km east-southeast of St John's, Newfoundland, and 35 km southeast of the giant Hibernia platform. The water is reasonably shallow at the Terra Nova site – just 90 to 100 metres deep – but the conditions are extremely harsh. In addition to sea ice and icebergs, the offshore operations will have to cope with cold, fog and heavy seas.

The development plan adopted by operator PetroCanada and its partners* involves an ice-strengthened, double-hull FPSO with processing capacity for 150,000 b/d of oil and storage capacity for 960,000 barrels of oil. The FPSO is provided with a quick-release turret mooring system with fluid connections to 24 wells on the seabed (14 production, seven water injection and three gas injection). The subsea Xmas trees and manifolds are installed in 'glory holes' to protect them from the scouring effect of passing icebergs, with oil wells drilled down to the reservoir some 3,200 metres below the seabed.

Ice management plan

The Terra Nova ice management plan was an important feature of the development application submitted to the government. The plan explains how the operator will deal with the hazards of both icebergs as well as pack sea ice. Intelligence is key to the success of this plan. During the ice season, an Ice Coordinator, based in St John's, will be responsible for collecting and collating ice detection and surveillance information and for relaying this data to an Ice Observer onboard the FPSO.

Every effort will be made to tow icebergs away from the FPSO by ropes deployed from the support vessels but, if these measures fail and an iceberg impact is unavoidable, then a controlled disconnection of the FPSO will take place. The vessel may also be disconnected if sea ice exceeds guidelines laid down in an ice alert chart. The Offshore Installation Manager (OIM) will have ultimate responsibility for ice management in the field.

Early detection of icebergs should enable the disconnection to take place in a controlled manner, with flushing and de-pressurising of risers and subsea equipment. A controlled disconnection of this type would be carried out in around four hours, it is claimed, but there is also provision for an emergency disconnection in just 15 minutes if an unexpected hazard emerges. After disconnection the FPSO will be capable of moving with its own thrusters to a position of safety.

During normal operation, the FPSO will be exposed to strong winds and to extremely cold air and sea conditions. As a result, great attention has been given to winterisation, insulation, heating, deck shielding and superstructure icing. The hull of the FPSO has been designed to support up to 2,000 tonnes of deck ice accumulation. A steam main has been fitted around the deck, with connection points for steam lances for ice removal. The vessel is designed to withstand the impact of icebergs weighing up to 100,000 tonnes moving at 0.5 metres/second.

FPSO fabrication

The FPSO is a Brown and Root PV 150 design – the hull and machinery were built at the Okpo shipyard of Daewoo Heavy Industries, in South Korea. The part-complete FPSO sailed from South Korea to Newfoundland under its own power, with the assistance of an escort tug. This 12,000 nautical mile voyage was accomplished at an average speed of 10 knots and included a transit of the Suez Canal.

After the completion of the voyage, the vessel arrived at Bull Arm, Newfoundland, for installation of the topside process modules last May. Two of the major topside process modules were built in the Barmac yard in Scotland, while the remaining two modules, flare stack and deck assemblies were built at the Bull Arm fabrication yard. The sharing of this work provided an opportunity for the exchange of technology between the more experienced Scottish yard, and the more newly established Canadian fabrication site.

Water ballast tanks are located outboard of the oil storage tanks within the hull of the FPSO. This layout provides a buffer zone to protect oil tanks in the event of collision, and is also said to simplify in-service inspection. An extra 3,000 tonnes of steel was added to the forward part of the hull to provide protection from the impact of icebergs and sea ice. The FPSO is capable of weathervaning around its turret mooring system – station keeping will be assisted by thrusters.

The disconnectable turret/swivel system was built by FMC subsidiary, SOFEC, and is being installed in the forward part of the hull during the vessel's stay at Bull Arm. This is the first system of its type to be built to cater for ice hazards, although disconnectable systems have been used in typhoon prone regions such as the South China Sea. The interface between the turret and the riser system is a 'spider buoy' that has been moored in position, ready for arrival of the FPSO.

The overall turret structure weighs 3,800 tonnes. The structure extends from the spider buoy beneath the keel to a swivel stack located high above the main deck – a total height of 70 metres. The swivel stack is basically a steel cylinder with a minimum diameter of 12 metres, fitted out with a number of decks to support manifolds, pigging systems, winches and control equipment. The turret is supported by an upper bearing at main deck level, with a lower bearing at keel level to restrain lateral movement.

The spider buoy is a substantial multi-compartment buoyant structure measuring 17 metres in diameter and 8 metres high. It is anchored to the seabed by nine mooring chains and has enough buoyancy to support the upper end of the flexible risers as it floats beneath the surface at a depth of around 35 metres. Connecting the FPSO first involves retrieval of the spider buoy. The buoy is then pulled into the base of the turret by a large-bore hydraulic tensioner system. It is then locked in position, with seals to ensure a watertight joint between buoy and turret.

The connections for individual risers take place inside a chamber in the lower part of the turret. This chamber resembles an upturned cup on a saucer, with the spider buoy forming the saucer. Quick disconnect valves located on either side of each riser connection are all enclosed within this chamber, once the spider buoy has been moved in position. The chamber will be pumped dry and purged with inert gas during normal operation. Vent shafts are provided to take any escaping hydrocarbons to a safe area – these vents are sealed by bursting disks during normal operation.

Fluids transfer

The method of transferring fluids to the process systems is similar to that adopted for other FPSO projects. The fluids are collected together by manifolds on the upper decks of the turret and are then transferred by a swivel stack from the (stationary) turret to process systems on the deck of the (weathervaning) FPSO. High pressure injection gas is passed though the swivel stack from the process deck to injection wells on the seabed. There is also provision for 'round trip' pigging of the flowlines to the subsea manifolds.

The subsea Xmas trees and production manifolds are located in 10-metre deep glory holes to protect them from damage from passing icebergs – the keels of large icebergs have been known to scrape gouges along the seabed as they drift over the Terra Nova site. This construction work was a critical part of the programme because wells could not be spudded until the seabed excavation had been completed. The work was managed by Coflexip Stena Offshore Newfoundland.

Unfortunately, the excavation work got off to a disappointing start in the 1998 summer construction season. So, in 1999, Boskalis Offshore's flagship vessel *The Queen of the Netherlands* was contracted to complete the work. The four glory holes necessary for production start-up, and a fifth glory hole for possible future development of the far east portion of the field, were completed in 1999.

The excavation work was performed by trailer suction dredging technology from the 173-metre long dynamically positioned vessel. This process involved dragging a 6.5-metre wide 'draghead' across the seafloor, which broke up the seabed material, then suction was used to draw the material up a 1.2-metre diameter arm into a hopper onboard the ship. The vessel sailed from the field to deposit the spoil.

Some initial fieldwork was carried out during 1999 by the drilling rig *Glomar Grand Banks* whilst delivery of a larger drilling unit, *Henry Goodrich*, was awaited. The latter is a fourth-generation rig designed to operate in harsh environments and was contracted from R&B Falcon initially for a two-year period, with options to renew. The most recent reports indicate that the *Henry Goodrich* has drilled and flow tested the six wells need for start of production. Five of the six wells were completed as of mid-June 2001.

Project delay

The original project timetable called for first oil to be achieved by the end of 2000, but an announcement in February stated that the start-up date had been revised to the 4Q2001. The project cost was also anticipated to rise to 15% above the previous estimate of C$2.5bn. Commenting on the delay, Norman McIntyre, PetroCanada Vice President, said the schedule and cost adjustments had arisen from an internal review of the project plan.

*Petro-Canada (33.99%) is the Terra Nova operator and acts on behalf of partners ExxonMobil Canada (22%), Husky Oil Operations (12.51%), Norsk Hydro Canada Oil and Gas (15%), Murphy Oil Company (12%), Mosbacher Operating (3.5%) and Chevron Canada Resources (1%).

Cost-effective oil well casing centraliser

A new spring steel oil well casing centraliser has been launched by Centek, specifically developed to overcome the problems faced by operators of horizontal and extended reach wells. Manufactured from one piece of specialised steel using a new cutting heat treatment process, the casing's advanced metallurgy results in a product that is less vulnerable to damage while also making it easier for the casing to be moved through the well bore, reports *Andy Jenner,* Design Engineer. It is able to withstand the extreme loads incurred and ensures that the casing remains central to the bore even when horizontal.

Developed partly in association with PERA (the Production Engineering Research Association), European test laboratories and metallurgists, the Centek centraliser has been designed to eliminate the risks of conventional spring units that might consist of up to 14 individual components. The extreme forces to which the centralisers are subjected when used in highly deviated, horizontal and extended reach wells makes them vulnerable to damage and disintegration within the well bore, with expensive consequences for the operator.

Advanced metal technology and new manufacturing techniques have been used by Centek so that the centraliser can be produced from a single piece of Boron steel and heat-treated to ensure uniform strength and flexibility. The finished product – which is currently pending a patent – is available at prices comparable to centralisers currrently on the market.

Well consultancy service

Based in Torquay, Devon, with offices in Aberdeen, Centek is offering its new centraliser as part of a consultancy service for well operators. An important part of this service includes the use of an exclusive software package that enables centraliser types and placements to be planned for maximum efficiency.

The program is able to model numerous factors within the well, including varying section coefficients of friction, variable densities arising from muds and cements that may be present, flotation section methods, tubular loads where the casing changes direction and rotational torque at the rig floor. Drilling company engineers can work with Centek personnel to conduct 'what if' simulations of the well so that the centraliser locations can be planned for optimum performance and economy.

Tough conditions

In the past, operators of vertically drilled wells have been able to rely on gravity to pull the casing into the bore and to use relatively few simple centralisers to keep the casing in position. However, the increased use of extended reach and horizontal wells subjects the centralisers to significantly greater forces. They are also required to lift the casing into the centre of the bore as it is pushed into its final position.

The centraliser must offer minimal axial friction against the lateral forces, and be sufficiently flexible to pass obstructions or undersize sections that may exist inside the well bore. Under such conditions a centraliser may be subjected to extreme forces that can put conventional spring centralisers at risk as they may be manufactured from steel leaf springs that are welded to softer steel bands that encircle the casing. Because the welding process used to join the spring to the band can affect the heat treatment of the spring, the centraliser becomes vulnerable to damage.

Other types of spring centraliser employing mechanical connections to the bands are also considered unsuitable as any movement at the join prevents the load from being distributed evenly around the centraliser. This prevents the load from being shared by the other springs in the centraliser and inhibits its ability to withstand the forces encountered.

Field trials

Before entering production with the present design of centraliser, Centek conducted field trials using a welded fabricated version. The concept was proved with 100% success and some 12,000 centralisers of this type have now been used in horizontal wells in European fields. The final design exceeded API 10D standards and subsequently passed the more demanding Shell SQAIR standards.

Manufacturing process

The nature of the manufacturing process enables quick production of centralisers tailored to the individual needs of the customer. These can include a high performance 'Slider' centraliser for use in long reach horizontal and close annulus wells, straight or spiral box configurations, rigid or positive stand-off designs and different types of two-part hinged construction. The most suitable option may be identified through the computer simulation service.

Market potential

With some 53,000 wells expected to be drilled worldwide in 2001 – of which 15,000 are expected to be horizontal or extended reach requiring a minimum of one centraliser for every 8-metre horizontal/extended reach section, the potential market is huge. The company plans to target the UK, Europe, Far East, Middle East and North African markets initially, and already has in place distribution agreements in SE Asia, Norway, Denmark, the Middle East and North Africa.

For further information, contact Centek on Tel: +44 (0)1803 324143 or Fax: +44 (0)1803 324145.

Tornado range powers on

Protector has unveiled a number product enhancements and extensions to its Tornado range of modular powered air purifying and airline respirators. For example, the T7 system is now compatible with three sizes of Vision full facemask, manufactured from liquid silicone rubber for wearer comfort and featuring a multi-curvature visor for the widest field of vision.

The Tornado welding headtop range – which features a secondary grinding screen so that the welding screen can be flipped up and respiratory protection maintained – has been enhanced with the new T4B, that features a cloth face seal connected directly to the welding shield to offer high comfort and simple operation. The T4B headtop is also offered in a brand new Tornado product – the Tor-Weld, which contains a full respiratory system for welders in a stand alone system contained in one box. It includes a blower, battery, charger, welding headtop, welding lens, particulate filters and full instructions.

Based on a proven Protector half-mask design, a new headtop – the T8 (see photo) – is claimed to provide 'exceptional comfort and fit' and is available in two sizes. The low profile design makes it compatible with other types of personal protection equipment such as welding shields, visors and goggles.

A new range of electronic welding lenses with auto-darkening properties has also been developed that is fully compatible with all Tornado welding headtops, states the company, as well as a new welding cape and flame retardent hose covers. A new range of Smart battery chargers is also available. Based on technology from the cellular phone industry, the chargers are claimed to not only decrease recharge times by over 50%, but also significantly increase battery life and enhance ease of use. Both single and 10-station chargers are included in the range.

Tel: +44 (0)1695 711711
Fax: +44 (0)1695 711764
e: **info@protector-tech.com**

Integrated product portfolio

Circor Instrumentation is introducing a number of new products as part of its new multi-company 'integrated product portfolio,' including Contromatics' 'Roughneck' ball valves available in a large choice of alloys and materials, and Hoke/Circle Seal Controls' XVH Series excess flow valves that automatically close leak-tight when a flow spike occurs to prevent uncontrolled release of system fluid at a low cost and with minimal maintenance. The excess flow valves are available in quick-acting automatic or manual reset versions and have a working range of 0 to 6,000 psig. Various seal and body materials are offered for use with a range of liquid or gas services and a choice of end systems is available to facilitate assembly in any system, states Circor.

GO HR-1 high-pressure hydraulic regulators have also been added to the Circor product range. Said to be particularly suited to wellhead control and other critical hydraulic applications, the regulators can handle up to 20,000 psi on the inlet and offer a range of highly stable outlet pressures and flow rates.

Tel: +44 (0)20 8423 0113
Fax: +44 (0)20 8423 5933
e: circor@circor.co.uk

Design versatility

The ISC (innovative standard cartridge) series of mechanical shaft seals available from Flowserve are designed for general purpose applications on ANSI and DIN process pumps. Within common gland and sleeve platforms, which cover either standard or enlarged bore configurations, interchangeable pusher and metal bellows sealing arrangements can be accommodated for both single and dual seal products. An optional elastomer bellows assembly is also available in the single seal variation.

'The design versatility combines operating economy with performance reliability, to help meet and even exceed a wide range of general process pump applications and environmental requirements,' states the company. Typical industries include oil refineries, chemical processing, water and wastewater, and many general industrial applications including food and beverage production.

The seal glands feature a universal slot fixing compatible with most pumps, and also accommodate a range of bolt circle diameters. In standard form, mating rings are manufactured from sintered silicon carbide and primary rings from premium resin grade carbon. These have robust face cross-sections for increased reliability, with homogeneous structures for stable performance in the pusher seal configuration, explains the company. The silicon carbide rings are held in compression and fully protected to ensure reliable equipment start-up.

Dual seal designs incorporate a pumping feature to give cooler operation. They are also double balanced to provide both pressurised and non-pressurised dual seal options for increased equipment dependability.

A wide range of shaft sizes are available. Maximum operating pressures vary with seal designs, from 10 bar to 20 bar, with working temperature ranging between –18°C and 204°C.

Tel: +44 (0)161 869 1200
Fax: +44 (0)161 869 1235
e: **spetter@flowserve.com**

Going the distance with Marathon diaphragm pumps

Following the successful launch of the Marathon metallic air-operated diaphragm pumps, sole UK distributor Gilbert Gilkes & Gordon of Kendal is now offering a new range of Marathon plastic air-operated double diaphragm pumps, manufactured by Warren Rupp.

The new rugged, moulded, all-bolted construction can be manufactured from PVDF, nylon, conductive acetyl and polypropylene and can handle abrasives easily, while the gentle pumping action does not sheer fragile materials, states the company. The non-corrosive body and chemically resistant hardware can safely pump caustic, toxic and corrosive materials, with the optional feature of spill containment to prevent leakage passing through the air valve system into the immediate atmosphere should a diaphragm fail. Mechanical, visual or electronic leak detection is also available.

Being air operated, the Marathon II range eliminates sparking and other problems associated with electrical or rotating pumps, making it ideal for hazardous or explosive environments. The pumps are reported to be capable of handling a range of viscosities, from liquids through to heavy or solid laden material.

The modular air distribution system (MADS) is said to facilitate easy in-line service, maintenance and repair without pump disassembly.

Unlike most air-operated diaphragm pumps, the Marathon range can be supplied with a stroke counter and batch control system which transforms the diaphragm pump into an accurate controllable system, states the company. The control system is said to offer all the benefits of programmable batch control, including the monitoring of pump strokes and fluid volumes with increased accuracy, without being over complicated and unreliable.

Available in sizes from $^1/_2$-inch to 3-inches, the Marathon II plastic pumps are claimed to offer a high volumetric efficiency providing lower air consumption patterns in comparison to other products currently available on the market.

Tel: +44 (0)1539 720028
Fax: +44 (0)1539 732110

Caught on camera in process sector

CCTV has traditionally used television technology that required specialist equipment to manage and transmit the pictures. However, this is now giving way to computer-based digital technology with dramatic changes to the cost benefit profile of investing in the equipment and an increase in the range of situations where the cameras can be deployed.

Suffolk-based P M E Electrical has developed a new CCTV digital camera currently being marketed to the process industry as a means of monitoring process and production. Digital CCTV installations have the advantage that they can be operated and managed centrally, with no need to visit the site to carry out routine maintenance and housekeeping. Image compression and picture change activated recording help reduce the cost of archiving and retrieving the required information. In addition, picture change generated alarms help reduce the number of false triggers that are so common with passive infra-red detectors, claims the company.

Such systems can perform an important safety function, as well as provide security surveillance. For example, in hazardous and difficult to reach areas, the digital cameras can provide a back-up monitoring system that will indicate if anyone in that area is in difficulty. They are also of value in disaster management – teams need to review a problem at the earliest opportunity and once on-site must liaise with technical specialists who may be hundreds of miles away; sharing CCTV pictures of the problems can help speed up the time to finding a solution.

P M E Electrical reports that it is currently seeking approval to ISO 9000/2 in order to make its entire range of electrical products and MrMinder CTTV services more marketable to the oil and petrochemical sectors.

Tel: +44 (0)1449 678639
Fax: +44 (0)1449 770290

Saving space

Ferguson Seacabs has introduced a new range of temporary building modules for use in all industries, including the oil and gas sector. Designed for ease of transportation and rapid set up, the Modupack can be flat-packed and stacked into the space of one-quarter of a pre-fabricated module, states the company. The new modules are also reported to be capable of side-by-side or end-to-end linkage to create multi-module complexes of limitless size.

By supplying the module in flat-pack format, the units can be transported in sets of eight on a standard road trailer, to significantly reduce transport costs. Once on location, unskilled personnel can easily assemble the Modupack, which is available in 8 ft by 10 ft, 20 ft and 30 ft options, in two to three hours. Electrical connections are also simply set-up within this timeframe, claims the company.

Tel: +44 (0)1467 626500
Fax: +44 (0)1467 626559

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

EVENTS Forthcoming

SEPTEMBER 2001

7–8 **Singapore**
Pacific Petroleum Insiders
Details: The Conference Connection, Singapore
Tel: +65 226 5280
Fax: +65 226 4117
e: info@cconnection.org

8–9 **Bergamo, Italy**
International Conference on Tankers: Evaluating the Current and Future Fundamental Issues
Details: Sarnico Studies and Training Centre, Italy
Tel: +39 035 9242 11
Fax: +39 035 9242 60
e: info@sarnicomanagement.it

10–11 **Singapore**
Petroleum Trading and International Law
Details: Abacus International, UK
Tel: +44(0)1953 497099
Fax: +44(0)1953 497098
e:Karen@abacus-int.com
www.abacus-int.com

9–12 **Alberta**
Changes Influencing International Negotiations – New Opportunities for Success
Details: Association of International Petroleum Negotiators (AIPN), Canada
Tel: +1 403 290 3155
Fax: +1 403 290 3517

11 **Wolverhampton**
Improving Safety in Petroleum Distribution
Details: Laura Viscione, IP
e: events@petroleum.co.uk

11–14 **St Petersburg**
Offshore Oil & Gas of the CIS
Details: RESTEC, Russia
Tel: +7 812 320 80 91
Fax: +7 812 320 80 90
e: oil&gas@restec.spb.su

11–14 **St Petersburg**
Development of the Russian Arctic Offshore
Details: RESTEC, Russia
Tel: +7 812 320 80 91
Fax: +7 812 320 80 90
e: oil&gas@restec.spb.su

12–13 **Singapore**
Petroleum Trading and Cargo Storages
Details: Abacus International, UK
Tel: +44(0)1953 497099
Fax: +44(0)1953 497098
e:Karen@abacus-int.com

12-13 **London**
Gas to Liquids IV
Details: SMi Energy Conferences, UK
Tel: +44(0)870 9090 711
e: customer_services@smi-online.co.uk
www.smi-online.co.uk

13–14 **Stavanger**
Station Keeping Seminar
Details: IMCA, UK
Tel: 44 (0)20 7931 8171
Fax: +44 (0)20 7931 8935
e: imca@imca-int.com
www.imca-int.com

15–18 **Dubai**
Arab Oil & Gas Show
Details: International Conferences and Exhibitions, UK
Tel: +44 (0)1442 878222
Fax: +44 (0)1442 879998
e: general@ice-ltd.demon.co.uk

17–18 **Dublin**
Irish Energy III
Details: SMi Conferences, UK
Tel: +44 (0)870 9090 711
Fax: +44 (0)20 7252 2272
www.smi-online.co.uk

17–18 **Houston**
Gas to Liquids – Viability, Economics and Strategy
Details: IBC Global Conferences, UK
Tel: +44 (0)20 7637 4383
Fax: +44 (0)20 7453 2058
e: sherri.wasmuth@informa.com

17–19 **Berlin**
ERTC Reliability Conference
Details: Global Technology Forum, UK
Tel: +44 (0)1737 365100
Fax: +44 (0)1737 353068
e: events@gtforum.com
www.gtforum.com

18–20 **London**
Advances in Risers, Moorings and Anchorings in Deepwater Fields
Details: IBC Global Conferences, UK
Tel: +44 (0)20 7637 4383
Fax: +44 (0)20 7453 205
e: sherri.wasmuth@informa.com

19–20 **Aberdeen**
Introducing Subsea Pipeline Engineering
Details: Trevor Jee Associates, UK
Tel: +44 (0)1892 544725
Fax: +44 (0)1892 544735
www.tja.co.uk

22–24 **Tehran**
15th Annual Conference – Middle East Strategy to the Year 2014
Details: APS London, UK
Tel: +44 (0)20 8997 3707
Fax: +44 (0)20 8566 7674
e: mailbox@biee.demon.co.uk

24–25 **Leeds**
Incineration of Municipal Waste with Energy Recovery
Details: University of Leeds, UK
Tel: +44 (0)113 233 2494
Fax: +44 (0)113 233 2511
e: cpd.speme@leeds.ac.uk

24-25 **London**
North Africa Oil & Gas Summit
Details: IBC Global Conferences, UK
Tel: +44(0)1932 893857
Fax: +44(0)1932 893894
e:cust.serv@informa.com

26 **Manchester**
RIBEX 2001
Details: Pira International, UK
Tel: +44(0) 1372 802046
Fax: +44 (0) 1372 802243
www.piranet.com

26 **London**
Cadman Memorial Lecture
Details: IP Conference Department,
e: events@petroleum.co.uk

27–28 **Berlin**
World Trade and Standardisation
Details: IFAN, Germany
Tel: +49 (0)30 26 01 2485
Fax: +49 (0)30 26 01 4 2485
e: uta@djadali@din.de

OCTOBER 2001

1–2 **London**
The Russian Oil and Gas Sector – Prospects and Opportunities for Growth and Development
Details: Laura Viscione,IP
e: events@petroleum.co.uk

2 **London**
IP Autumn Lunch 2001
Details: IP Conference Department,
e: events@petroleum.co.uk

10–11 **The Netherlands**
The Re-use of Offshore Production Facilities – Making it Happen
Details: Marijke van Ravenzwaaij, The Netherlands
Tel: +31 223 684 161
Fax: +31 223 683 125
e: info@ato.nl

17–19 **Rio de Janeiro**
13th Annual Deep Offshore Technology
Details: Pennwell, UK
Tel: +44 (0)1992 656652
Fax: +44 (0)1992 656735

Membership News

NEW MEMBERS

Mr A Aguguo, Willbros (Nigeria) Limited
Ms M Coutakis, Aberdeen
Mr C R Deddis, Aberdeen
Dr E W Gorczynski, Sunbury-on-Thames
Mr J A Greenhough, Shell UK Oil Products
Ms S Kavindele, Kroll Associates
Mr J H Kirk, Terminal Automation Services Limited
Mr R Lee, Motortrade Services
Mr C L Obianwu, BC Moore and Associates
Mr W Permsantithum, Thai Oil Company Limited
Ms K L Rhodes, Petroleum Venture Management Limited
Mr S E T Round, Solvent Resource Management Limited
Mr J C Rushton, Orkney
Mr P A Russell, Marlow
Mr A Sachdev, Arthur Andersen
Mr G A Simpson, European Project Consultants Limited
Mr R Taylor, Nottingham Centre for Pavement Engineering
Mr A Wells, Romford

STUDENTS

Mr A Adeosun, Dundee
Ms P Atienza, London
Mr G P Chauny, London
Mr J P Davies, London
Ms M Dike, Dundee
Mr J Munro, Aberdeen

NEW FELLOW

Mr A R Hull FInstPet
Andy Hull joined the petroleum industry in 1968, initially with Shell-Mex and BP Ltd transferring in 1976 to Shell UK Ltd where he has worked throughout the UK in the Group's downstream business in commercial marketing and project management. Since 1992 he has been Shell's Commercial HSE Consultant, advising management, staff and customers as well as more recently acting as Dangerous Goods Safety Advisor in a number of Shell distributor businesses. In 1993 Mr Hull joined the Committee of the IP's London Branch and in 1997 was elected Chairman of the Branch, a position he held for four years. He retired from Shell at the end of August but remains a Member of London Branch Committee

NEW CORPORATES

Tasca Tankers Ltd, Unit 3, Moor Park Business Centre, Thornes Moor Road, Wakefield WF2 8NZ, UK
Tel:+44 (0)1924 369007 Fax: +44 (0)1924 369069
e: **sales@tascatankers.ltd.uk** Web: **www.tascatankers.ltd.uk**
Representative: Mr P A Grinyer, Area Sales Manager
One of the UK's leading manufacturers of road tankers for the petroleum and LP gas industries, manufacturing new vehicles, remounts, repairs etc.

Taylor Gibson Associates Ltd, 14 Titan Court, Laporte Way, Luton, Beds LU4 8EF, UK
Tel: +44 (0)1582 486886 Fax: +44 (0)1582 486860
Web: **www.tgadesign.co.uk**
Representative: Ms D Wilkinson, Director
Print and media resource agency for BP Oil.

Tamdec, Jetty No 886, Road No 115, North Sitra Industrial Area 601, Bahrain, PO Box 26346
Tel: +9 73 73 68 68 Fax: +9 73 73 56 21
e: **info@tamdec.com** Web: **www.tamdec.com**
Representative: Mr Jassim Amiri, President
Crude oil and petroleum products brokers

DEATHS

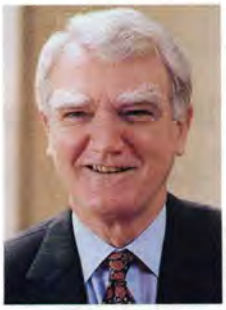
We have recently been notified of the deaths of the following Members:

	Born
Mr F Blades	1915
Dr K J Hugil	1965
Mr M Lonsdale	1925
Mr J S Wilson	1929

IP Conferences and Exhibitions

Cadman Memorial Lecture

Springboard for Progress – Building on the Energy Industry's Record for Responsiveness



Sir Mark Moody-Stuart KCMG (right)
Former Chairman of the Royal Dutch/Shell Group of Companies

Gibson Hall, Bishopsgate, London EC2: Wednesday 26 September 2001, 16.30 for 17.00

Admission, strictly by ticket only, is free of charge. In the event of the Lecture being oversubscribed, priority will be given to IP Members. Tickets and further information are available from the IP Conference Department.

IP THE INSTITUTE OF PETROLEUM

Seminar and Exhibition

Improving Safety in Petroleum Distribution

Tuesday 11 September
Wolverhampton Science Park, Wolverhampton, UK

For more information please contact the IP Conference Department
Tel: +44 (0)20 7467 7100 e: *events@petroleum.co.uk*

The IP's Distribution and Marketing Safety Committee's new seminar providing information on new initiatives, disseminating new IP guidance, and advising pertinent regulatory developments for SH&E professionals and managers of distribution terminals, distribution contractors and authorised contractors.

For further information on these events please contact the IP Conference Department
Tel: +44 (0)20 7467 7100 Fax: +44 (0)20 7580 2230
e: *events@petroleum.co.uk* or view the IP website: *www.petroleum.co.uk*

The Russian Oil and Gas Sector: Prospects and Opportunities for Growth and Development

in association with **AFTP, Confitec, DGMK** *and* **Trade Partners UK**

London: 1–2 October 2001

Risk Management for Russian Crude and Product Trade – Prospects and Challenges for Building a Domestic Russian Oil and Product Futures Market

Workshop: London 3 October 2001

Full details from the IP Conference Department.

Topics will include:

- **European Liberalisation of the Oil & Gas Market and EU/Russian Cooperation**
- **Current Reserves Structure and Forecasts for the Future**
- **Upstream Infrastructure Development**
- **Transportation and Distribution**
- **Financing Solutions**
- **Improving Management and Resource Allocation**

Speakers include:

- **Gurami J Avalishvili, First Deputy Energy Minister, Russia**
- **Stephen O'Sullivan, United Financial Group**
- **Yuri Beylin, Yukos E&P**
- **Alexander Belousov, Deputy Minister of Natural Resources, Russia***
- **Professor Constantine Milovidov, Gubkin University**
- **Stanislav Vasilenko, Pridneprovskiye Oil Pipelines**
- **Kairgeldy Kobyldin, KazTransOil**
- **Professor Leonid Sorkin, Dr of Technical Sciences and Chairman of the Board of Petrocom**
- **Sergei Mayorov, Mosco Interbank Currency Exchange**

*invited

IP Discussion Groups & Events

Energy, Economics, Environment

'Implications of the Gas and Electricity Crisis in the US'

by **Graham Weale,** Director, European Energy Studies, Primark WEFA Ltd

19 September 2001, 17.00 for 17.30 at the Institute of Petroleum, 61 New Cavendish Street, London W1G 7AR, UK

Contact: Laura Viscione Tel: +44 (0)20 7467 7100

Energy, Economics, Environment

'West Africa – the Elephants' Graveyard'

by **Joseph Bryant,** President, Angola Business Unit, BP Exploration Operating Company

11 October 2001, 17.00 for 17.30 at the Institute of Petroleum, 61 New Cavendish Street, London W1G 7AR, UK

Contact: Laura Viscione Tel: +44 (0)20 7467 7100

Energy, Economics, Environment

'Merger Strategies and Outcomes – Winners and Losers in Oil and Gas Investments'

by **Martin Lovegrove,**
Harrison Lovegrove & Co. Ltd

30 October 2001, 17.00 for 17.30 at the Institute of Petroleum, 61 New Cavendish Street, London W1G 7AR, UK

Contact: Laura Viscione Tel: +44 (0)20 7467 7100

Offshore Europe

Visit the IP at Stand 1188 Blue Zone at Offshore Europe, Aberdeen 4–7 September 2001

IP THE INSTITUTE OF PETROLEUM

Branch Activities

Southern

Contact:	*Veronica Cloke Browne* *Tel: +44 (0)1962 715399*
TBA Sep:	Talk by West Moors School of Petroleum, by Colonel Stuart Addy
TBA Sep:	Visit to local industrial plant
23 Oct:	The Distribution of Petroleum Products by Pipeline by Mike Longman

Institute of Petroleum, Midlands Branch joint meeting with British Lubricants Federation, Midlands Branch

Two papers given by De Montfort University

Current and Future Demands for Hydraulic Fluids and Distance Learning

Papers by Professor Malcolm Fox and Dr Sarah-Jane Davies

Wednesday 17 October 2001, Worcester, UK

For more details please contact:
Margaret Ward, c/o Mike Ward Associates
Tel: +44 (0)1299 896654 Fax: +44 (0)1299 896955
e: **margaretward@mikewardassociates.co.uk**

Guidelines for the analysis of jackup and fixed platform well conductor systems

These new guidelines are intended for engineers concerned with offshore production, drilling, completion or workover well operations from fixed (seabed founded) platforms and mobile jackup drilling units. This publication provides information and guidance on those issues that affect the overall structural strength, integrity and operability of such well systems. In this context the well systems include conductor tubulars, surface casing string tubulars, surface blow-out preventers (BOPs including flanges and other connections), surface xmas trees (including flanges and other connections) and surface risers (ie those joining surface wellheads to surface BOPs). Any of these items that are present are primary structural components and the integrity of the entire well system is dependent upon their suitability for the particular application.

ISBN 0 85293 284 7 £80.00 (25% discount for IP Members)

SPECIAL OFFER

Guidelines for routine and non-routine subsea operations from floating vessels

Guide to safe practice for those concerned with drilling, completion or workover operation from floating vessels. Provides information and guidance on issues which affect the structural strength and integrity of the subsea system. This guide was published in 1995.

ISBN 0 85293 156 5 (Full price £80.00) *Available for £40.00 when purchased with* Guidelines for the analysis of jackup and fixed platform well conductor systems*

*For each copy of *Guidelines for the analysis of jackup and fixed platform well conductor systems*, purchasers are entitled to buy one copy of *Guidelines for routine and non-routine subsea operations from floating vessels* at the special offer rate.

Petroleum Measurement Paper Number 9: The Performance of Turbine Meters in Loading Gantries – A Review of Proving and Test Data

Part X, Section 10, of the Petroleum Measurement Manual specifies the procedures for proving turbine meters in road or rail loading gantry installations. The procedures are based on those employed for proving positive displacement meters, but make allowance for the special requirements of turbine meters. Many of the problems associated with the use of turbine meters in the limited space available and with the variations of pipework in gantry installations have been appreciated for some time. The magnitude of the effects and the actions that may be taken to mitigate them are less well understood.

Industry has generated a significant amount of data on the performance of turbine meters, both through special test programmes and through routine proving. This Petroleum Measurement Paper presents data derived from this work (made available by the oil companies involved) and from research programmes sponsored by the IP to provide the basis for the proving recommendations.

Summaries of the results are presented and discussed below under three separate headings:

- Data derived from routine proving operations.
- Data generated during field tests or trials.
- Data produced in flow laboratory tests or other tests under controlled conditions.

ISBN 0 85293 343 6 £36.00 (25% discount for IP Members)

Petroleum Measurement Manual: Part X Meter Proving – Section 10

Recommended UK Operational Practice for Proving Turbine Meters in Loading Gantries

It is important that a gantry meter is reading accurately and to comply with regulations, it is necessary to carry out periodically a test or series of tests in which the meter's readings are compared with proving equipment that is traceable to national standards.

This Part of the Petroleum Measurement Manual describes procedures applicable to turbine gantry meters (road and rail) proved by reference meter or volumetric proving tank. The primary objective of this Manual is to promote uniformity and consistency both in the proving of gantry meters and in the interpretation of the results.

Reference should also be made to Petroleum Measurement Paper No 9: The Performance of Turbine Meters in Loading Gantries – A Review of Proving and Test Data.

ISBN 0 85293 344 4 £42.00 (25% discount for IP Members)

Available for sale from Portland Press Ltd inc. postage in Europe (outside Europe add £5.00). Contact Portland Press Ltd, Commerce Way, Whitehall Industrial Estate, Colchester CO2 8HP, UK. Tel: +44 (0)1206 796351. Fax: +44 (0)1206 799331. e: sales@portlandpress.com

For further information please contact the IP Publications Department on +44 (0)20 7467 7100

NEW Publications

Reception Facilities for Tankers*

(Available from Intertanko, Bogstadveien 27B, PO Box 5804 Majorstua, N-0308 Oslo, Norway). 125 pages. Price: $100 Intertanko member; $200 non-member.

The availability of adequate shore reception facilities worldwide is essential if pollution of the marine environment is to be avoided. In spite of the increased ratification of the 1973/78 MARPOL Convention and its 1997 Protocol, the provision of reception facilities is still well below the level it should be, states Intertanko – the International Association of Independent Tanker Owners. Now in its fourth edition, this publication provides an updated list of facilities currently available worldwide. Wherever possible, details of the method of disposal at each facility are included, along with discharge capacity limitations and the relevant costs. Information on the disposal of chemical wastes and garbage is also incorporated and reference is made to companies providing the various services.

The Kuwait Oil & Gas Report

Khashayar Bahar (SMi Publishing, No 1 New Concordia Wharf, Mill Street, London SE1 2BB, UK). ISBN 1 862 06067 3. 87 pages. Price: £595 UK; £635 outside UK.

Kuwait continues to explore for new oil deposits, in particular reservoirs of light crude. This report includes an economic profile of the country, its GDP and growth, external accounts and finance, financial infrastructure and investment, as well as a political summary, including its relations with Arab and Western countries. It provides a history of the Kuwaiti oil and gas industry, concessions and post-nationalisation developments, including its role in Opec, and details of oil and gas reserves and production, field developments, exploration opportunities, oil refining, oil exports, LPG, and oil and gas pricing. Also featured is an analysis of domestic oil, gas and power consumption; a list of government and private contacts and regulators; and a list of current projects on tender in the oil, gas, power and petrochemical sectors.

Gaming the System*

James B Rieley (Financial Times Prentice Hall, Edinburgh Gate, Harlow CM20 2JE, UK). ISBN 0 273 65419 5. 162 pages. Price: £21.99.

In a world in which organisations are facing an ongoing struggle to improve their outcomes, it has become increasingly clear that by simply 'cranking up' the productivity targets, the organisational gains are rarely sustainable. Of all the issues facing companies that are inhibiting this ability, it is the organisational population's ability to 'game the system' that limits the success of initiatives. This book identifies how structures in organisations (both explicit and implicit policies and procedures, stated goals, and mental models) drive behaviours that are detrimental to long-term organisational success. It uses case studies to show how to identify these behaviours and to develop ways in which to counteract the negative effects that minimise long-term personal and company potential.

Port State Control*

Dr Z Oya Ozcayir (LLP, Informa Publishing Group, Sheepen Place, Colchester, Essex CO3 3LP, UK). ISBN 1 85978 485 2. 430 pages. Price: £140 ($238) hardback.

There are numerous different regional agreements in place for port state control. Each one aims to prevent the operation of sub-standard ships. Under these programmes, if a ship fails the inspection of a port authority it may be detained in that port until all defects on that ship have been rectified. This book provides a detailed analysis of all the issues relating to port state control. It examines each of the regional agreements currently in place; discusses port state control in the UK and US; considers the recent EC Directive; looks at the ISM Code and classification societies; and also covers the recent *Erika* incident and its aftermath. It also includes coverage of compensation and lengths of detainment.

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- *Forecourt Trader Supplier Directory 2001/2002*. 5th edition. Edited by Merril Boulton, William Reed Directories, Crawley, UK, 2001.
- *Introduction to Mineral Sciences*. 1st edition. Andrew Putnis, Cambridge University Press, Cambridge, UK, 2001.
- *Invertebrate Palaeontology and Evolution*. 4th edition. E N K Clarkson, Blackwell Science, Oxford, UK, 1998.
- *Occupational Exposure Limits 2001: Containing the List of Maximum Exposure Limits and Occupational Exposure Standards for use with Control of Substances Hazardous to Health Regulations 1999*. EH40/2001. Health and Safety Executive (HSE), London, UK, 2001.
- *Offshore Oil and Gas Directory 2001/2002*. 27th edition. Miller Freeman Information Services, Miller Freeman, Tonbridge, UK, 2001.
- *Steel Pipelines for High Pressure Gas Transmission*. IGE/TD/1Communication 1670. 4th edition. Institution of Gas Engineers (IGE), London, UK, 2001.
- *Vertebrate Palaeontology*. 2nd edition. Michael J Benton, Blackwell Science, Oxford, UK, 2000.
- *Vertically Integrated Oil Companies of Russia: Formation Methodology and Realization*. Vagit Yussupovich Alekperov, Moscow, Russia, 1996.

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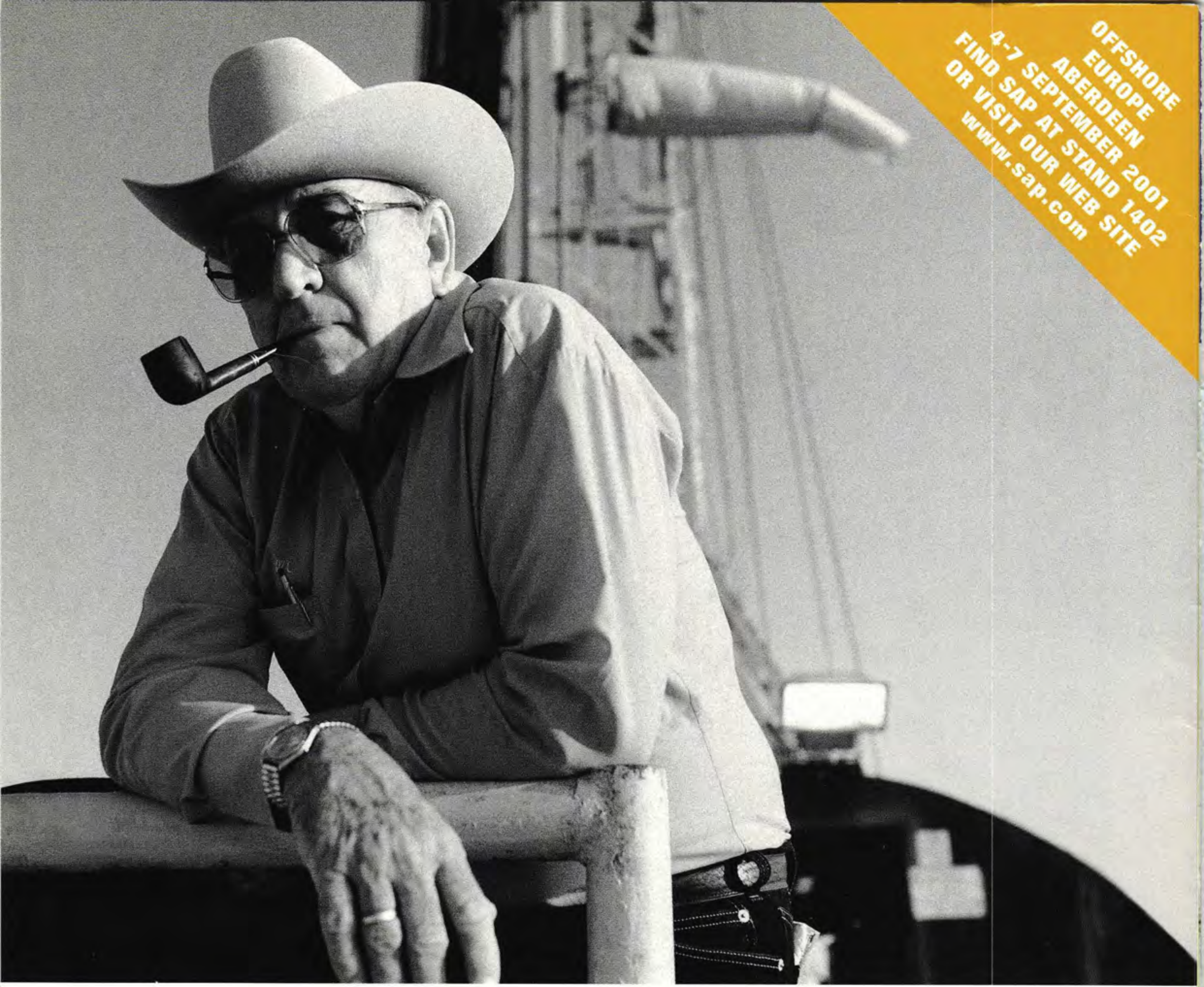

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